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Safety Evaluation Related to Extended Power Uprate at

R.E. Ginna Nuclear Power Plant

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 97 TO RENEWED FACILITY

OPERATING LICENSE NO. DPR-18

R.E. GINNA NUCLEAR POWER PLANT, INC.

R.E. GINNA NUCLEAR POWER PLANT

DOCKET NO. 50-244

1.0 INTRODUCTION

1.1 Application

By application dated July 7, 2005, as supplemented by letters dated August 15, September 30, and December 6, 9, and 22, 2005, and January 11 and 25, February 16, March 3 and 24, and May 9 and 19, 2006 (Agencywide Documents Access and Management System (ADAMS) Accession Nos. ML051950123, ML052310155, ML052800223, ML053480388, ML053480362, ML053640080, ML060180262, ML060960416, ML060540349, ML060810218, ML060940312, ML061350375 and ML061450381, respectively), R.E. Ginna Nuclear Power Plant, LLC (the licensee) requested changes to the Renewed Facility Operating License and Technical Specifications (TSs) for the R.E. Ginna Nuclear Power Plant (Ginna). The supplemental letters dated August 15, September 30, December 6, 9, and 22, 2005, and January 11 and 25, February 16, and March 3 and 24, and May 9 and 18, 2006, provided additional clarifying information that did not expand the scope of the initial application as published in the *Federal Register* on September 22, 2005 (70 FR 55633).

The proposed changes would increase the maximum steady-state reactor core power level from 1520 megawatts thermal (MWt) to 1775 MWt, which is an increase of approximately 16.8 percent. The proposed increase in power level is considered an extended power uprate (EPU).

1.2 Background

1.2.1 General Design Features

Ginna is a pressurized-water reactor (PWR) plant of the Westinghouse 2-Loop design with a vertical, cylindrical reinforced-concrete type containment with prestressed tendons in the vertical wall, reinforced-concrete ring anchored to the bedrock and a reinforced hemispherical dome. A welded steel liner is attached to the inside face of the concrete shell to ensure a high degree of leak tightness.

The Ginna site is on the south shore of Lake Ontario about 16 miles east of Rochester, New York, an urban area with a population of about 750,000.

1.2.2 Systematic Evaluation Program (SEP)

As stated in Section 1.3 of the Ginna Updated Final Safety Analysis Report (UFSAR), the discussion of general design criteria is divided into two parts. UFSAR Section 3.1.1 discusses the general design criteria used during the original licensing of Ginna. The criteria used at that time comprised the proposed Atomic Industrial Forum (AIF) versions of the criteria issued for comment by the Atomic Energy Commission on July 10, 1967, and defined or described the safety objectives and approaches incorporated in the design of this plant. UFSAR Section 3.1.2 discusses the adequacy of the Ginna design relative to the 1972 version of the General Design Criteria in Appendix A to 10 CFR Part 50 and describes the conformance at Ginna to the 1972 version of the General Design Criteria.

In February 1978, the Nuclear Regulatory Commission (NRC) initiated a SEP for 11 operating plants that had received construction permits between 1956 and 1967. (The construction permit for Ginna was issued on April 25, 1966.) The SEP consisted of a plant-by-plant limited reassessment of these plants to review the designs of these older plants to reconfirm and document their design safety because the safety criteria had changed since the plants were originally licensed. The purpose of the review was to provide: (1) an assessment of how these plants compared with the current licensing safety requirements relating to selected issues, (2) a basis for deciding on how these differences should be resolved in an integrated plant review, and (3) a documented evaluation of plant safety. As part of the SEP, the original codes and standards used in the design of structures, systems, and components at Ginna were compared with later licensing criteria based on Regulatory Guide (RG) 1.26 and Section 50.55a, “Codes and standards,” of Part 50 of Title 10 of the *Code of Federal Regulations* (10 CFR). The objective was to assess the capability of the structures, systems, and components to perform their safety functions as judged by the later standards. Several areas were identified where requirements had changed; however, all areas were satisfactorily resolved. The results for Ginna were documented in NRC Report NUREG-0821, “Integrated Plant Safety Assessment, Systematic Evaluation Program, R.E. Ginna Nuclear Power Plant, Final Report,” December 1982 (ADAMS No. 8309200476).

1.2.3 Original and Renewed Plant License

The NRC originally licensed Ginna on September 19, 1969, under Provisional Operating License No. DPR-18, for operation at 1520 MWt. The plant began commercial operation in July 1970 and was operated at 1300 MWt until March 1972, when the licensee increased power to 1520 MWt. On December 10, 1984, Facility Operating License DPR-18 was issued and superseded the provisional license in its entirety, allowing the plant to continue to be operated at 1520 MWt. Thus, the proposed EPU to 1775 MWt would result in an increase of approximately 16.8% over the original and current licensed power level for Ginna.

On May 19, 2004, the NRC renewed the operating license for Ginna, which shall expire at midnight on September 18, 2029.

1.2.4 Unique Design Features

Ginna has the following special features/unique designs:

1.2.4.1 Emergency Core Cooling System (ECCS) Low Pressure Injection Flow Path

The discharges of the two residual heat removal (RHR) pumps and heat exchangers feed a common injection line which penetrates containment. This line then divides into two redundant core deluge flow paths each containing a normally closed motor operated isolation valve and check valve which provide injection into the reactor vessel (RV) upper plenum.

1.2.4.2 Steam Generators

The original Westinghouse Model 44 steam generators (SGs) were replaced in 1996 with SGs designed and manufactured by Babcock & Wilcox, Canada, that have a larger heat transfer surface to accommodate the EPU conditions. Since the average reactor coolant system (RCS) temperature (T_{avg}) will be increased, the estimated SG secondary pressure will increase from 770 to 798 psia.

1.2.4.3 Service and Circulating Water Systems

The total nominal flow of circulating water through the turbine condenser circulating water system (CWS) and service water system (SWS) is about 400,000 gpm. Approximately 340,000 gpm is used in the CW system and the rest is available for the SW supply and fire protection systems. In addition, domestic-quality water at a flow of about 100,000 gal/day is purchased from the Ontario Water District, Town of Ontario, for drinking, sanitary purposes, auxiliary boiler feed, and condensate makeup and polishing.

Lake Ontario is the source of the CWS, which is taken through the eight ports (17.3-ft-wide by 10-ft-high) of the submerged octagonal intake structure that lies about 3100 ft offshore in about 33 ft of water at mean lake level of 244.7 ft. Each port is screened for large debris with heated bars spaced 10 to 14 inches apart; the screens can be heated electrically to minimize accumulation of frazil ice. The water flows by gravity through a 10-ft diameter concrete-lined tunnel into the screen house, where it passes through a fine-mesh traveling screen before being pumped through the CWS or SWS. The water from these two systems is combined and is released to the discharge canal, which opens into Lake Ontario at the shoreline. The discharge canal is protected from large debris by a submarine net placed inside the canal near the shoreline.

1.2.4.4 Auxiliary Feedwater (AFW) Systems

The AFW system includes two motor-driven pumps and one steam turbine-driven pump. Since the pumps are susceptible to damage from the effects of line breaks in the main steam and feedwater lines and the AFW steam and feedwater lines, the licensee installed a standby AFW (SAFW) system adjacent to the auxiliary building. The SAFW system consists of 2 independent 100% capacity subsystems in the SAFW pumphouse, which is a seismic category I concrete structure remote from high-energy lines. The discharge from the SAFW pumps is routed through the auxiliary building, enters the containment through penetrations remote from the main steam and feedwater lines, and connects to the feedwater lines near each SG with check valves near the connection to minimize the amount of line pressurized during normal plant operation. The SAFW pumps take suction from the SW loops inside the auxiliary building. An interlock prevents starting a SAFW pump when its associated AFW pump is running on the EDG.

1.2.4.5 Station Blackout (SBO) Coping

Additional safety features independent of the emergency ac power distribution system available at Ginna include the 200%-capacity turbine-driven AFW system (TDAFW), a diesel-driven air compressor, which can charge the instrument air and service air systems, a diesel-driven fire pump taking suction from Lake Ontario, which can provide an inexhaustible source of secondary cooling water to the SGs, and a technical support center battery system, with 2880 amp-hr capacity, which can be cross-connected to either station battery to supply vital loads on one train for much longer than the 4-hour coping period.

1.2.4.6 Spent Fuel Storage

The original spent fuel storage racks provided capacity for the storage of 210 fuel assemblies. In 1976, the NRC approved the replacement of the original racks with higher density flux trap type racks, which expanded the storage capability to 595 fuel assemblies.

In 1984, the NRC approved the conversion of 6 flux trap type racks to high-density fixed poison type racks, which further expanded the storage capacity to 1016 fuel assemblies. In addition, the spent fuel pool (SFP) was divided into two regions. Region 1 comprised three flux trap type racks to accommodate a full core off-load. Region 2 consisted of 6 high-density fixed poison (Boraflex) type racks for the storage of 840 fuel assemblies that satisfied minimum burnup criteria and had cooled for a minimum of 60 days.

In 1998, the NRC approved re-racking the SFP to reconfigure the pool to accommodate a net increase of 353 locations. This is accomplished by retaining the 6 existing high-density region 2 racks (840 minus 12 for attachment of new racks = 828 locations) and installing new borated stainless steel (BSS) racks with up to 541 additional storage locations for a total of 1369 storage locations after completion of both phases. The pool has three types of racks in two regions. Region 1 contains new high-density flux-trap design BSS racks designated as type 3 for fresh and spent fuel. Region 2 contains the existing Boraflex racks designated as type 1 and new high-density BSS racks designated as type 2. With the completion of phase 1, the pool contains 1321 storage locations. In addition to intact fuel assemblies, consolidated fuel canisters can also be stored in region 1 and region 2 of the pool.

In 1985, the NRC approved the storage of consolidated fuel in the SFP. This process involves placing spent fuel containing, at most, all the rods from two standard spent fuel assemblies, which have decayed at least 5 years, into one canister. The canisters are designed to hold 358 fuel rods and can be placed in either region 1 or region 2 rack locations. The canisters are fabricated from stainless steel. The number of fuel rods contained in the intact fuel assemblies and/or consolidated rod storage canisters is limited to no more than the number of rods contained in 1879 fuel assemblies (179 fuel rods per assembly x 1879 assemblies = 336,341 fuel rods). The TSs limit storage at this time to 1879 fuel assemblies.

1.2.5 Associated TS Amendments

1.2.5.1 Main Feedwater Isolation Valves

Amendment No. 95, dated March 16, 2006, revised TS Section 3.7.3, “Main Feedwater Regulating Valves (MFRVs), Associated Bypass Valves, and Main Feedwater Pump Discharge Valves (MFPDVs),” to allow the use of the main feedwater isolation valves (MFIVs) in lieu of the MFPDVs to provide isolation capability to the SGs in the event of a steam line break. (See Reference 75)

1.2.5.2 Revised Loss-of-Coolant Accident (LOCA) Analyses

Amendment No. 96, dated May 31, 2006, revised TS 3.5.1, “Accumulators,” and TS 3.5.4, “Refueling Water Storage Tank (RWST),” to reflect the results of revised analyses performed to accommodate a planned power uprate for the facility and revise TS 5.6.5, “Core Operating Limits Report (COLR),” to permit the use of NRC-approved methodology for large-break and small-break loss-of-coolant accidents (LBLOCAs and SBLOCAs). (See Reference 76)

1.2.5.3 Revised Axial Offset Control

Amendment No. 94, dated February 15, 2006, revised the TSs to allow the use of Relaxed Axial Offset Control (RAOC) methodology in reducing operator action required to maintain conformance with power distribution control TS and increasing the ability to return to power after a plant trip or transient while still maintaining margin to safety limits under all operating conditions. (See Reference 53)

1.3 Licensee’s Approach to EPU

The licensee's application for the proposed EPU follows the guidance in the Office of Nuclear Reactor Regulation’s (NRR’s) Review Standard (RS)-001, "Review Standard for Extended Power Uprates," to the extent that the review standard is consistent with the design basis of the plant. Where differences exist between the plant-specific design basis and RS-001, the licensee described the differences and provided evaluations consistent with the design basis of the plant. As part of its July 7, 2005, application, the licensee used Westinghouse Electric Company Report WCAP-16461-P, "Ginna Station Extended Power Uprate Supplemental Information," (Proprietary) (hereafter referred to as the licensing report).

The licensee selected the proposed uprated power level for Ginna based upon a review of the original design and current power level of a comparable two-loop plant (Kewaunee Nuclear Plant), which is operating at a core power level of 1772 MWt. Table 1.0-1 of the licensing report provides a comparison of the key design parameters for Ginna and Kewaunee. Both plants will operate at about the same power level and RCS pressure. The thermal design flow (TDF) at Kewaunee is about 4.5% higher than at Ginna, and Kewaunee’s average vessel coolant temperature (T_{avg}) is about 0.5% lower than at Ginna. The RCS volume of the Kewaunee plant is 351 cu ft greater than Ginna, and 200 cu ft of that volume difference is located in Kewaunee’s pressurizer.

The proposed EPU represents a core power increase of almost 16.8% above the current core power 1520 MWt. No changes are being made to the minimum RCS total TDF of 170,200 gpm. The increase in core power will be accomplished by increasing the core temperature and enthalpy rise. The licensee proposes to operate Ginna within a full-power T_{avg} range of 564.6 EF to 576 EF.

An accounting of how the core power increase would be accomplished, from the current core power to the EPU core power, at both ends of the T_{avg} range, follows:

	1. Core Mass Flow (10^6 lb/hr)	2. Core Outlet Temp (EF)	3. Core Outlet Enthalpy (BTU/lb)	4. Core Inlet Temp (EF)	5. Core Inlet Enthalpy (BTU/lb)	6. Core Power Level (BTU/hr)	Ratio: EPU to Current Power
Currently (1520 MWt)	60.4	607.80	624.52	543.10	538.58	5.192E9	
EPU 564.6 EF (1775 MWt)	61.5	604.70	619.99	528.90	521.39	6.064E9	1.17
EPU 576 EF (1775 MWt)	60.6	615.4	635.90	540.90	535.89	6.059E9	1.17

1. Core mass flow is based upon the volumetric TDF, less 6.5% for core bypass flow, and the density of water at the reactor coolant pump discharge pressure (2295 psia).
2. Core outlet temperature is the unmixed value (with no contribution from bypass flow).
3. Core outlet enthalpy is obtained from ASME compressed water tables at 2250 psia.
4. Core inlet temperature is also used to determine the cold leg water density for the mass flow calculation.
5. Core inlet enthalpy is obtained from ASME compressed water tables at 2295 psia.
6. Core power is the product of mass flow and core enthalpy rise.

The EPU core power level, assumed in the accident analyses supporting the licensing report, is increased by 2% to 1811 MWt to account for uncertainties, which the licensee states may be reduced in the future as part of a measurement uncertainty recapture power (MURP) uprate. The addition of 6 MWt for the two reactor coolant pumps (RCPs) brings the nuclear steam supply system power level to 1817 MWt.

The licensee plans to implement the EPU in one step. The licensee plans to make the modifications necessary to implement the EPU during the refueling outage in fall 2006. Subsequently, the plant will be operating at 1775 MWt starting in Cycle 33.

1.4 Plant Modifications

Three major modifications were completed in the last 10 years that provided Ginna with the capability to increase power with minimal additional modifications of the reactor and plant safety systems. These modifications were: (1) re-tubing the main condenser in 1995, (2) replacement of the SGs with an oversized design in 1996, and (3) replacement of the RV head in 2003. The licensee has determined that several additional plant modifications are necessary to implement the proposed EPU. The following is a list of these modifications that the licensee will complete during the fall 2006 refueling outage:

- High-pressure turbine and turbine control valves replacement

- Fast-acting feedwater isolation valve operator installation
- First region of upgraded fuel assemblies used in core reload
- Main feedwater pump impellers/motors replacement
- Main feedwater regulating valves
- Condensate booster pump (2) replacement
- Moisture separator reheater relief valves replacement
- Drain and vent piping and valves replacement
- Generator condensate cooler replacement
- Iso-phase bus duct cooling modifications
- Oilstatic cable monitoring instrumentation
- Various main steam supports modifications
- Generator protection and voltage regulator setting changes
- Various instrument replacements
- SAFW valve modification
- Condensate storage tank overfill line modification
- Oilstatic cable differential current protection relay monitoring instrumentation
- Water solid cooldown spool pieces
- Control rod position indication modification
- Turbine driven AFW pump valve local controller
- Charging pump control power disconnect switch
- Charging pump backup air tank installation
- 'B' steam generator level instrument modification
- Main turbine gland sealing steam spillover modification

The following modifications were already completed during the spring 2005 refueling outage:

- Main generator monitoring instrumentation modification
- Condensate booster pump (1) and motor (3) replacement
- New fuel handling equipment installation
- Main transformer bushing replacement and cooler modification
- Main generator exciter coupling keyway modification

With exception of the high-pressure turbine rotor, the required modifications are generally of small scope. The activities needed to produce thermal power increases are a combination of those that directly produce more power and those that will accommodate the effects of the power increase. The primary means of producing more power are a change in the fuel design, an operational change in reactor thermal-hydraulic (T-H) parameters, and upgrade of the balance of plant capacity by component replacement or modification. Other changes include replacing the high-pressure turbine, replacing selected feedwater and condensate motors that are already operating at capacity, providing additional cooling for some plant systems, various electrical upgrades to accommodate the higher currents and to improve electrical stability, modifications to accommodate greater steam and condensate flow rates, and instrumentation upgrades that include replacing parts, changing setpoints and modifying software.

The NRC staff's evaluation of the licensee's proposed plant modifications is provided in Section 2.0 of this safety evaluation (SE).

1.5 Method of NRC Staff Review

The NRC staff reviewed the licensee's application to ensure that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) activities proposed will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public. The purpose of the NRC staff's review is to evaluate the licensee's assessment of the impact of the proposed EPU on design-basis analyses.

The NRC staff evaluated the licensee's application and supplements. The NRC staff's evaluation included an audit of Westinghouse calculations (Reference 30), upon which certain accident analyses, presented in the uprating application, were based. The staff focused upon event analyses that are (1) sensitive to the plant's uprated conditions, and (2) analyzed with methods that have not been heretofore applied in the Ginna docket. Specifically, several NRC staff members visited Westinghouse's offices in Monroeville, Pennsylvania, on November 1 - 3, 2005, and audited calculations that supported most of the licensee's analyses, including the SBLOCA, the steam line break, feedwater line break, and loss of feedwater analyses. At the staff's request, Westinghouse made available copies of these calculations, and its internal analysis guidelines, for use by the staff, at their liaison office near Rockville, Maryland. These documents are subject to applicable proprietary-information withholding controls. In addition, Westinghouse permitted members of the NRC staff to access and use the LOFTRAN code (Reference 32), including applicable input data, for the purpose of making confirmatory calculations and performing sensitivity studies. Most of the non-LOCA accident analyses, reported in the licensing report, are based upon the results of RETRAN (Reference 33) simulations. LOFTRAN and RETRAN are whole-plant simulation codes that have been accepted by the NRC staff for licensing applications. The NRC staff also performed independent calculations related to the SBLOCA, and long-term cooling (boron precipitation) analyses.

In areas where the licensee and its contractors used NRC-approved methods in performing analyses related to the proposed EPU, the NRC staff reviewed relevant material to ensure that the licensee/contractor used the methods consistent with the limitations and restrictions placed on the methods. In addition, the NRC staff considered the effects of the changes in plant operating conditions on the use of these methods to ensure that the methods are appropriate for use at the proposed EPU conditions. Details of the NRC staff's review are provided in Section 2.0 of this safety evaluation (SE).

2.0 EVALUATION

2.1 Materials and Chemical Engineering

2.1.1 Reactor Vessel Materials Surveillance Program

Regulatory Evaluation

The reactor vessel (RV) material surveillance program provides a means for determining and monitoring the fracture toughness of the RV beltline materials to support analyses for ensuring the structural integrity of the ferritic components of the RV. Appendix H to 10 CFR Part 50 provides the staff's requirements for the design and implementation of the RV material surveillance program. The NRC staff's review primarily focused on the effects of the proposed EPU on the licensee's RV surveillance capsule withdrawal schedule. The NRC's acceptance criteria are based on: (1) General Design Criterion (GDC) 14, which requires that the reactor coolant pressure boundary (RCPB) be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture; (2) GDC 31, which requires that the RCPB be designed with a margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; (3) 10 CFR Part 50, Appendix H, which provides for monitoring changes in the fracture toughness properties of materials in the RV beltline region; and (4) 10 CFR 50.60, which requires compliance with the requirements of 10 CFR Part 50, Appendix H. Specific review criteria are contained in NRC Standard Review Plan (SRP) Section 5.3.1 (Reference 21) and other guidance provided in Matrix 1 of Review Standard RS-001.

Technical Evaluation

Regarding the Ginna RV surveillance program and capsule withdrawal schedule, the licensee concluded in Section 2.1.1.2.6 of the licensing report:

> Ginna has evaluated the effects of the proposed EPU on the reactor vessel surveillance withdrawal schedule and concludes that it has adequately addressed changes in neutron fluence and their effects on the schedule.

The updated calculation of ΔRT_{NDT} is documented in Table 2.1.1-4 of the licensing report, and it shows that the maximum ΔRT_{NDT} using the uprated fluence projections for Ginna at 54 effective full power years (EFPYs) is greater than 200 EF. Per American Society for Testing and Materials (ASTM) Standard E185-82, this ΔRT_{NDT} value requires that five capsules be withdrawn. This quantity is unchanged from the current withdrawal schedule. Thus, the only changes to the current withdrawal schedule are to the updated capsule fluence values, lead factors, and the notes referring to the timing of the future withdrawals. The updated withdrawal schedule is documented in Table 2.1.1-5 of the licensing report.

The licensee has already withdrawn four capsules (V, R, T, and S). The fourth capsule, S, was withdrawn at a peak capsule fluence of 3.64×10^{19} n/cm^2 (E > 1.0 MeV). The peak vessel end of license (EOL) fluence including the EPU is 5.42×10^{19} n/cm^2. The fifth capsule, N, is planned to be removed shortly after receiving a fast neutron fluence equivalent to approximately 54 effective full-power years (EFPY) (estimated capsule fluence of 5.45×10^{19} n/cm^2). Thus, the fluence on capsule N is expected to be between 1 and 2 times the peak vessel EOL fluence. The estimated time of withdrawal will be during the fall 2006 refueling outage. The last capsule, P, will be removed shortly after it accumulates a fluence equivalent to 80 years of operation. The specific withdrawal EFPY and fluence will be determined following the analysis of Capsule N. Thus, the applicant will have data for 60 years of operation and will be able to monitor neutron flux throughout the period of operation.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the RV surveillance capsule withdrawal schedule and concludes that the licensee has adequately addressed changes in neutron fluence and their effects on the schedule. The NRC staff further concludes that the RV capsule withdrawal schedule is appropriate to ensure that the material surveillance program will continue to meet the requirements of Appendix H to 10 CFR Part 50 and 10 CFR 50.60, and will provide the licensee with information to ensure continued compliance with GDC 14 and GDC 31 in this respect following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the RV material surveillance program.

2.1.2 Pressure-Temperature Limits and Upper Shelf Energy

Regulatory Evaluation

Appendix G to 10 CFR Part 50 provides fracture toughness requirements for ferritic materials (low alloy steel and carbon steel) materials in the RCPB, including requirements on the upper shelf energy (USE) values used for assessing the remaining safety margins of the RV materials against ductile tearing and requirements for calculating pressure-temperature (P-T) limits for the plant. These P-T limits are established to ensure the structural integrity of the ferritic components of the RCPB during any condition of normal operation, including anticipated operational occurrences and hydrostatic tests. The NRC staff’s review of the USE assessments covered the impact of the EPU on the neutron fluence values for the RV beltline materials and the USE values for the RV materials through the end of the current licensed operating period for Ginna. The NRC staff’s P-T limits review covered the P-T limits methodology and the calculations for the number of the EFPY specified for the proposed EPU, considering neutron embrittlement effects and using linear elastic fracture mechanics.

The NRC’s acceptance criteria for P-T limits and USE are based on: (1) GDC 14, which requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture; (2) GDC 31, which requires that the RCPB be designed with a margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; (3) 10 CFR Part 50, Appendix G, which specifies fracture toughness requirements for ferritic components of the RCPB; and (4) 10 CFR 50.60, which requires compliance with the requirements of 10 CFR Part 50, Appendix G. Specific review criteria are contained in SRP Section 5.3.2 and other guidance provided in Matrix 1 of Review Standard RS-001.

Technical Evaluation

Regarding the topic of the RV P-T limits, the licensee concluded in Section 2.1.2.2.5 of the licensing report that:

> ... the revised fluence projections associated with the proposed EPU did not exceed the fluence projections used in developing the current adjusted reference temperature (ART) values for Ginna at 28 EFPYs.

The ART calculation used the peak fluence of 3.11E19 n/cm^2 (E > 1.0 MeV) for 28 EFPY.

In response to a request for additional information (RAI), the licensee confirmed that the peak reactor vessel fluence at 28 EFPY using EPU fluence is projected to be 2.91E19 n/cm^2 (E > 1.0 MeV). Thus, the P-T limits contained in the Ginna PTLR remain valid up to 28 EFPY.

The ART values calculated for the P-T limits including consideration of the EPU are less than that used in the generation of current P-T limits (28 EFPY). Thus, there will be no impact on the P-T limit curves. Therefore, the NRC staff concludes that the licensee's proposal to limit the existing heatup and cooldown curves to a period of applicability through 28 EFPY of operation is acceptable and consistent with the requirements of Appendix G to 10 CFR Part 50.

In response to an NRC staff RAI, the licensee provided the updated equivalent margin analysis (EMA) to reflect EPU condition. Based on this analysis, the licensee concluded that:

> All beltline materials are expected to have a USE greater than 50 ft-lb through the end of renewed life (54 EFPY) except the intermediate-to-lower shell girth weld and the intermediate-to-nozzle shell girth weld. The updated EMA analysis reflecting the EPU condition for the Ginna intermediate to lower shell girth weld and the nozzle to intermediate shell girth welds show more than sufficient margin for USE after the power uprate.

To confirm that the licensee's analysis satisfied the criteria in ASME Code, Section XI, Appendix K, the NRC staff performed an independent analysis using the methodologies and models specified in RG 1.161, "Evaluation of Reactor Pressure Vessels With Charpy Upper-Shelf Energy Less Than 50 ft-lb," NUREG/CR-5729, "Multivariable Modeling of Pressure Vessel and Piping J-R Data," and ASME Code, Section XI, Appendix K. The NRC staff confirmed the applicant's conclusion that the Ginna RV would have margins of safety against ductile tearing equivalent to those required by Appendix G to Section XI of the ASME Code.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the P-T limits for the plant and USE values for the RV beltline materials. The staff concludes that the licensee has adequately addressed changes in neutron fluence and their impacts on the P-T limits for the plant and USE values for the Ginna RV. The staff concludes that the Ginna RV beltline materials will continue to have acceptable USE, as mandated by Appendix G to 10 CFR Part 50 through the expiration of the license for the facility. The NRC staff also concludes that the licensee has demonstrated the validity of the current P-T limits for operation under the proposed EPU conditions. Based on this assessment, the NRC staff concludes that the Ginna facility will continue to meet the requirements of 10 CFR Part 50, Appendix G, and 10 CFR 50.60 and will enable the licensee to comply with GDC 14 and GDC 31 in this respect following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the P-T limits and USE.

2.1.3 Pressurized Thermal Shock

Regulatory Evaluation

The pressurized thermal shock (PTS) evaluation provides a means for assessing the susceptibility of the RV beltline materials to PTS events to assure that adequate fracture toughness is provided for supporting reactor operation. The NRC staff's requirements, methods of evaluation, and safety criteria for PTS assessments are given in 10 CFR 50.61. The NRC staff's review covered the PTS methodology and the calculations for the reference temperature (RT_{PTS}) at the expiration of the license, considering neutron embrittlement effects. The NRC's acceptance criteria for PTS is based on: (1) GDC 14, which requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating fracture, and of gross rupture; (2) GDC 31, which requires that the RCPB be designed with a margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; and (3) 10 CFR 50.61, which sets fracture toughness criteria for protection against PTS events. Specific review criteria are contained in SRP Section 5.3.2 and other guidance provided in Matrix 1 of Review Standard RS-001.

Technical Evaluation

Regarding the topics of PTS analyses for the Ginna RV, the licensee provided RT_{PTS} values for the beltline materials of the RV and concluded:

> The effect of higher fluence projections is minimal for PTS, raising the PTS value for the limiting material from 270.6 EF to 273 EF, a value below the 300 EF allowable.
>
> . . .
>
> Ginna further concludes that the evaluation has demonstrated that the plant will continue to meet the Ginna Station current licensing basis requirements with respect to GDC 14, GDC 31, and 10 CFR 50.61, following implementation of the proposed EPU.

The NRC staff has evaluated the information provided by the licensee as well as information contained in the staff's RV Integrity Database. Based on the revised EPU fluence, the staff independently confirmed that the Ginna RV materials would continue to meeting the PTS screening criteria requirements of 10 CFR 50.61.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the PTS analysis for the plant and concludes that the licensee has adequately addressed changes in neutron fluence and their effects on PTS. The NRC staff further concludes that the licensee has demonstrated that the plant will continue to meet the requirements of GDC 14, GDC 31, and 10 CFR 50.61 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to PTS.

2.1.4 Reactor Internal and Core Support Materials

Regulatory Evaluation

The reactor internals and core supports include structures, systems, and components (SSCs) that perform safety functions whose failure could affect safety functions performed by other SSCs. These safety functions include reactivity monitoring and control, core cooling, and fission product confinement (within both the fuel cladding and the RCS). The NRC staff's review covered the materials' specifications and mechanical properties, welds, welds controls, nondestructive examination procedures, corrosion resistance, and susceptibility to degradation. The NRC's acceptance criteria for reactor internal and core support materials are based on GDC 1 and 10 CFR 50.55a for material specifications, controls on welding, and inspection of reactor internals and core supports. Specific review criteria are contained in SRP Section 4.5.2 and other review criteria and guidance are provided in Matrix 1 of Review Standard RS-001. Matrix 1 provides references to the NRC's approval of the recommended guidelines for RV internals in Westinghouse Topical Report WCAP-14577, Revision 1-A, "License Renewal Evaluation: Aging Management for Reactor Internals (March 2001)," and Babcock and Wilcox Report BAW-2248A, "Demonstration of the Management of Aging Effects for the Reactor Vessel Internals (March 2000)."

Technical Evaluation

The licensee discussed the impact of the EPU on the structural integrity of the Ginna RV internal components in Section 2.1.4 of the EPU licensing report. In its licensing report for the EPU, the licensee concluded that the new EPU environmental conditions (chemistry, temperature, and fluence) will not introduce any new aging effects on reactor internal components during 60 years of operation, nor will the EPU change the manner in which component aging will be managed by the aging management program credited in the topical report WCAP-14577.

The RV internals of PWR-designed light-water reactors may be susceptible to the following aging effects:

- Cracking ! induced by thermal cycling (fatigue-induced cracking), stress-corrosion cracking (SCC), or irradiation assisted stress-corrosion cracking (IASCC)
- Loss of fracture toughness properties ! induced by irradiation exposure for all stainless steel grades, or the synergistic effects of irradiation exposure and thermal aging for cast austenitic stainless steel (CASS) grades
- Stress relaxation in bolted, fastened, keyed or pinned RV internal components ! induced by irradiation exposure and/or exposure to elevated temperatures

- Void swelling (induced by irradiation exposure)

Matrix 1 of Review Standard RS-001 provides the NRC staff's basis for evaluating the potential for EPUs to induce these aging effects. In Table Matrix-1, the staff states that, in addition to the SRP, guidance on the neutron irradiation-related threshold levels inducing IASCC in RV internal components are given in WCAP-14577. WCAP-14577 establishes a threshold of 1 X 10^{21} n/cm^2 (E > 1.0 MeV) for the initiation of IASCC, loss of fracture toughness, and/or void swelling in PWR RV internal components made from stainless steel (including cast austenitic stainless steels) or Alloy 600/82/182 materials.

In its RAI, the staff informed Ginna that, consistent with Table Matrix-1, either an inspection plan would need to be established to manage the age related degradation in the Ginna RV internals, or that a commitment would be needed indicating that the licensee would participate in the industry's initiatives on age-related degradation of PWR RV internal components. In its December 6, 2005, letter, the licensee stated the current Inservice Inspection (ISI) Program would be used to manage the aging effects associated with the RV internal components. The program satisfies the requirements of ASME Code, Section XI, 1995 Edition including 1996 Addenda. For every 10-year ISI period, the primary inspection activities of the Ginna ISI Program include:

- During every refueling period within the 10-year interval, the accessibility areas of the vessel interior are examined using the VT-3 method.
- Interior attachments within and beyond the beltline region are examined utilizing VT-1 and VT-3 methods.
- The core support structure is removed and all accessible surfaces are examined using the VT-3 method.

In addition to the ASME Code, Section XI ISI Program, the licensee is actively participating in the Material Reliability Program (MRP), Issue Task Group (MRP-ITG) effort for augmented inspection of the RV internals. This effort will use industry data as plant-specific analyses to determine initial locations, initial crack sizes, and flaw tolerance for calculated stresses, fluences, and temperatures. The licensee confirmed that it will implement enhanced examination techniques for RV internals, consistent with the development of these techniques.

The licensee is following its ASME Code, Section XI ISI Program and has also made the commitments to participate in the industry's research program for degradation of PWR RV internal components and to develop an inspection program for the RV internals that is based on the recommendations of the industry initiatives that are consistent with Table Matrix-1 of RS-001. Therefore, the licensee's approach for addressing RV internals under EPU conditions is acceptable. Based on this assessment, the NRC staff concludes that the licensee has established an acceptable course of action for managing age-related degradation in the Ginna RV internals under the EPU conditions for the unit.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the susceptibility of reactor internal and core support materials to known degradation mechanisms and concludes that the licensee has identified appropriate degradation management programs to address the effects of changes in operating temperature and neutron fluence on the integrity of reactor internal and core support materials. The NRC staff further concludes that the licensee has demonstrated that the reactor internal and core support materials will continue to be acceptable and will continue to meet the requirements of GDC 1 and 10 CFR 50.55a following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to reactor internal and core support materials.

The NRC staff has reviewed the licensee’s proposed application to increase the rated core thermal power for Ginna by 16.8% and has evaluated the impact that the EPU conditions will have on the structural integrity assessments for the RV and RV internals. The staff has determined that the proposed license amendment will not significantly impact the remaining safety margins required for the following RCS-related structural integrity assessments: (1) RV Surveillance Program, (2) USE assessment for the RV, (3) P-T limits for the RV, (4) PTS assessment for the RV beltline materials, and (5) structural integrity assessment of the RV internal components, in that the licensee has committed to the establishment of a plant-specific inspection program for the RV internals.

Therefore, the NRC staff determined that the proposed power uprate will not significantly impact the operation of the RV, the RV internals, and the RCPB materials, and therefore, the staff finds the requested power uprate acceptable with respect to the evaluation of the RV internal and core support materials.

2.1.5 Reactor Coolant Pressure Boundary Materials

Regulatory Evaluation

The RCPB defines the boundary of systems and components containing the high-pressure fluids produced in the reactor. The NRC staff’s review of the RCPB materials covered the design specifications, compatibility with the reactor coolant, fabrication and processing, susceptibility to degradation, and degradation management programs. The NRC’s acceptance criteria for RCPB materials are based on: (1) 10 CFR 50.55a and GDC 1, insofar as they require that SSCs important to safety be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing and postulated accidents; (3) GDC 14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture; (4) GDC 31, insofar as it requires that the RCPB be designed with margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; and (5) 10 CFR 50.55a, Part 50, Appendix G, which specifies fracture toughness requirements for ferritic components of the RCPB. Specific review criteria are contained in SRP Section 5.2.3 and other guidance provided in Matrix 1 of RS-001. Additional review guidance for primary water stress-corrosion cracking (PWSCC) of dissimilar metal welds and associated inspection programs is contained in Generic Letter (GL) 97-01, Information Notice (IN) 00-17, Bulletin (BL) 01-01, BL 02-01, and BL 02-02. Additional review guidance for thermal embrittlement of cast austenitic stainless steel components is contained in a letter from the NRC to the Nuclear Energy Institute (NEI), dated May 19, 2000. The licensee evaluated the effect of the proposed service conditions on the performance of RCS materials by using Electric Power Research Institute (EPRI) chemistry guidelines under "PWR Primary Water Chemistry Guidelines: Vol. 1, Rev. 5, TR-1002884," EPRI-MRP-117, "Inspection Plan for Reactor Vessel Closure Head Penetrations in US Power Plants," dated July 2004, and NRC First Revised Order dated February 20, 2004.

Technical Evaluation

The licensee indicated that the RCPB defines the boundary of systems and components containing the high-pressure fluids produced in the reactor. The Ginna evaluation of RCPB materials covered the design specifications, compatibility with the reactor coolant, fabrication and processing, susceptibility to degradation, and degradation management programs.

a. Austenitic Stainless Steels

The two degradation mechanisms that are applicable to austenitic stainless steels in the reactor coolant environment are intergranular stress-corrosion cracking (IGSCC) and transgranular stress-corrosion cracking (TGSCC). Sensitized microstructure, susceptible materials, and the presence of oxygen are required for the occurrence of IGSCC, while the introduction of halogens such as chlorides and the presence of oxygen are prerequisites for the occurrence of TGSCC. The chemistry changes resulting from uprating do not involve introduction of any of these contributors so that no effect on material degradation is expected in the stainless steel components as a result of the power uprate.

The licensee stated that the proposed Lithium (Li), Boron (B), and pH management program meets EPRI chemistry guidelines under "PWR Primary Water Chemistry Guidelines: Vol. 1, Rev. 5, TR-1002884." Since these guidelines are specifically designed to prevent fuel cladding corrosion effects, specifically fuel deposit build-up, there will be no adverse effect on fuel cladding corrosion as a result of the proposed power uprate. Experience with operating plants as well as with the guidelines provided by EPRI suggest that increasing initial Li concentrations of up to 3.5 ppm with controlled B concentrations to maintain pH values between 6.9 to 7.4 has not produced any undesirable fuel cladding material integrity issues. Ginna plans to maintain Li levels at 3.5 ppm or less and thus no adverse effects from this aspect on the power uprate is expected to occur.

b. Alloy 600/82/182 Components

The licensee stated that Alloy 600 and Alloy 82/182 weld deposits are present in the Ginna RCS at the following locations:

C Bottom-mounted instrumentation (BMI) penetrations in the bottom head of the RV. The instrument nozzles are Alloy 600, welded to the ID of the head with partial penetration welds using 82/182 weld deposit.

C Radial core support lugs in the lower shell of the RV. The core support lugs are Alloy 600 welded to the interior surface of the shell with 82/182 weld deposit.

C Primary tube sheet surface of the replacement SGs (RSGs). The primary surface of each RSG tube sheet (carbon steel) is weld overlaid with alloy 82 weld deposit.

Alloy 690 and Alloy 52/152 weld deposits are present at the following locations:

C U-tubes of the RSGs. The tubing for the RSGs was Alloy 690 TT (thermally treated).

C Weld-deposited “butter” layers on the weld preparations of the primary inlet and outlet nozzles in the channel heads of the RSGs are Alloy 52/152.

C Divider plates in the channel heads of the RSGs are Alloy 690 plate material welded to the primary tube sheet surface of each generator with Alloy 52/152.

C Control rod drive mechanism (CRDM) nozzles, vent nozzle, and instrument nozzles in the replacement RV head. All nozzles are Alloy 690 TT and welded to the inside diameter (ID) of the head with partial penetration welds using Alloy 52 weld deposit.

c. Effect of EPU on PWSCC susceptibility of RV closure head (RVCH) penetrations

At Ginna, the RVCH with Alloy 600/82/182 penetrations was replaced during 2003 with a new head comprised of Alloy 690/52/152 CRDM penetrations. Laboratory and field experience to date suggests that Alloy 690 and its associated 52/152 welds are resistant to PWSCC under conditions typically found in the head. Even though an increase of 8.6 EF in the closure head is predicted due to the EPU at Ginna, the proposed uprate is not expected to have any impact on the PWSCC degradation of the Alloy 690/52/152 RVCH penetrations, according to the licensee. In addition to the upgraded material, due to the limited field data available, the requirements of First Revised Order EA-03-009 dated February 20, 2004 (the Order), was listed by the licensee to ensure the safe management of the PWSCC issue. In addition to listing the NRC requirements under the Order, the licensee listed EPRI-MRP-117, “Inspection Plan for Reactor Vessel Closure Head Penetrations in US Power Plants,” July 2004. The licensee also stated that it will continue to monitor the industry programs and recommendations to manage the issue for the new vessel head and take appropriate actions as necessary. Based on the licensee’s listing of the requirements rather than providing a formal commitment to follow the Order and MRP guidance, the staff requested that the licensee provide a more specific commitment as to what requirements will be followed by Ginna or reference the pertinent commitment(s) that were accepted by the staff when it approved license renewal to assure the effects of PWSCC will be managed. Under its evaluation of the effects of the 8.6 EF increase in temperature due to the EPU, the licensee had listed the inspection requirements under First Revised Order EA-03-009, EPRI-MRP-117, and a potential ASME Code Case as requirements to manage the effects of PWSCC on Alloy 690/52/152 materials. The licensee also stated that Ginna will continue to monitor the industry programs and recommendations to manage the issue for the new vessel head and take appropriate actions as necessary.

In its supplemental letter dated December 19, 2005, the licensee stated that in its March 8, 2004, response to the Order, that it would comply with the requirements as specified in the Order. The Ginna response to NRC Bulletin 2003-02 is contained in its letters dated

September 19 and December 9, 2003. The licensee stated that it was one of the first PWRs to replace the RVCH. Furthermore, commitments for the Ginna license renewal effort associated with the RV lower head penetrations are documented in NUREG-1786, "License Renewal Safety Evaluation Report [SER] for the R.E. Ginna Nuclear Power Plant" (license renewal SER), which include: (1) the continuation of the inspections of the thimble tubes for wear, (2) the initiation of the inspections of the thimble tubes for SCC beginning 2009, and (3) the performance of VT-1 quality inspections at the stainless steel fillet welds and bottom mounted instrumentation (BMI) nozzle to the safe end welds, which was modified to a combination of VT-1 and VT-3 examination per an April 8, 2005, response. Based on the discussion above and the staff's approval of the aging management programs and licensee commitments in NUREG-1786, the NRC staff concludes that the effects of PWSCC will be adequately managed.

d. Effect on the PWSCC Susceptibility of Alloy 600/82/182 BMI Penetrations

The licensee stated that the BMI penetrations at Ginna are made of PWSCC-susceptible Alloy 600/82/182 materials. The service temperature data listed under Table 2.2.5-1 suggests that the EPU reduces the susceptibility to PWSCC due to a 3.2 EF decrease in service temperature at the BMI. The licensee stated that Ginna BMIs are subject to NRC Bulletin 2003-02 and that MRP 2004-04 recommended certain inspections be performed. Based on the information provided by the licensee, the NRC staff requested that the licensee provide a more specific commitment as to what requirements will be followed by Ginna or reference the pertinent commitment(s) that were accepted by the staff when approving license renewal to assure the effects of PWSCC will be managed. Under its evaluation of the effects of the 3.2 EF decrease in BMI penetrations temperature due to the EPU, the licensee had listed the inspection requirements that may apply such as MRP guidance and NRC Bulletin 2003-02. As described in item c above, the licensee responded to these issues in its December 19 letter.

Based on the discussion above and the NRC staff's approval of the aging management programs and licensee commitments in NUREG-1786, the NRC staff concludes that the effects of PWSCC will be adequately managed.

e. Thermal Aging of Cast Austenitic Stainless Steels (CASS)

The licensee stated that at Ginna a small increase (8.6 EF) in the hot leg temperature was assessed due to the EPU and that the effect of this change in the service temperature on the thermal aging is considered. The Westinghouse Report WCAP-14575-A, "License Renewal Evaluation: Aging Management Evaluation for Class 1 Piping and Associated Pressure Boundary Components," indicates that thermal aging causes reduction in fracture toughness of the CASS component material and hence reduction in the critical flaw size that could lead to component failure. The impacted RCPB CASS components include primary piping and its welds, valve bodies and pump casings. The WCAP-14575-A proposed programs to manage the effects of thermal aging of CASS components during the period of extended operation. The NRC's assessment of these programs is contained in Section 3.3.3 of NUREG-1786.

In addition to the above, on page 2.1.5-4 of the licensing report, the licensee stated that a reconciliation of the final SER for WCAP-14575-A lists applicant action items in Table 3.2.0-1.2 of the license renewal application. Based on the information provided by the licensee, the NRC staff requested that the licensee discuss in detail what the applicant action items are for the subject WCAP and why the 8.6 EF increase in temperature due to the EPU is acceptable since there are action items associated with the WCAP that are referenced as the basis for its acceptability. Further, the staff asked that the licensee discuss how the programs under the subject WCAP would adequately manage any increased thermal aging (if any) due to the 8.6 EF temperature increase.

Under its assessment of the effects of thermal aging of CASS, the licensee had indicated that programs were proposed in WCAP-14575-A to manage the effects of thermal aging of CASS components. This was discussed under Section 3.3.3 of NUREG-1786. Furthermore, the licensee stated that a reconciliation of the subject WCAP lists applicant action items in Table 3.2.0-1.2 of its license renewal licensing report. Finally, the licensee stated that the 8.6 EF increase in the hot leg temperature was assessed due to the EPU and that the effect of this change in the service temperature on the thermal aging is considered.

In its December 19, 2005, letter, the licensee stated that the action item specified in Table 3.2.0-1.2 of the Ginna license renewal licensing report related to the assessment of effects of thermal aging of CASS included an analysis of potential loss of fracture toughness during the period of extended operation (60 years). The licensee stated that this is described in Section B2.1.34 of Appendix B to the license renewal application. The action items were approved by the NRC staff in its SER in NUREG -1786 and are, therefore, acceptable.

The licensee stated that it had performed a specific leak-before-break (LBB) flaw evaluation considering the effects of the CASS RCS primary loop piping elbows under WCAP-15837, "Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for R.E. Ginna Power Plant for the License Renewal Program," April 2002. It was shown in WCAP-15837 that there is a large margin available considering the saturation fracture toughness values for the RCS including CASS elbows during the period of extended operation of 60 years. WCAP-15837 was approved by the staff in Section 4.7.7 of NUREG-1786. To support the EPU at the Ginna Station, the existing LBB analyses documented in WCAP-15837 were evaluated to address the proposed EPU conditions. The maximum stresses at the critical locations were impacted by less than 1%. It was concluded that an increase of the hot leg temperature of 8.6 EF due to EPU had negligible effects on the flaw stability analysis in WCAP-15837 for the primary loop piping. There was also an insignificant impact on the fracture toughness values due to thermal aging as a result of the 8.6 EF increase of the hot leg temperature. The licensee stated that the effect of the EPU was considered on the RCS cold leg and was considered insignificant. Based on the discussion above and the licensee's response to the staff's RAI, the staff concludes that the licensee has demonstrated that the effects of thermal aging on CASS materials due to the 8.6 EF increase in hot leg temperature will be negligible.

f. Pressure-Retaining Components and Component Supports

Section 2.2.2 of the licensee's submittal summarizes the evaluations and results of the licensee's review on the effects of the proposed EPU on the design input parameters and the design-basis loads and load combinations for normal operating, upset, emergency, and faulted conditions for NSSS piping, components, and supports. The licensee stated that its review covered the impact of higher EPU flow rates on flow -induced vibration in more susceptible components. The licensee's review included a comparison of the resulting stresses and cumulative fatigue usage factors against the code-allowable limits. The acceptance criteria as denoted in RS-001 and GDC 1, 2, 4, 14, and 15 were used by the licensee. In addition to GDC compliance, the pressure retaining components and supports were evaluated for plant license renewal, which is documented in NUREG-1786.

The primary concern from the proposed power uprate is the potential effect of changes in the RCS chemistry (impurities) and pH conditions, and the power uprate service temperatures on the integrity of RCS component materials during service. These concerns include general corrosion (wastage) and stress corrosion cracking (SCC) of system materials, fuels corrosion, and PWSCC of nickel-based alloys. The staff's review of the EPU design parameters (license renewal application Section 1.1), Nuclear Steam Supply System Parameters, and Table 1-1 indicates that the following changes in the RCS chemistry and service temperature conditions will occur during operations after the EPU implementation:

- The post-EPU reactor coolant lithium/boron program is coordinated such that an elevated 7.2 pH value is maintained during the fuel cycle (up to 1500 ppm boron) while maintaining a maximum lithium level of less than or close to 3.5 ppm (elevated chemistry).

- A maximum increase ΔT in the peak steady state service temperature of 8.6 °F at the RVCH and hot leg locations and a decrease ΔT in service temperature of 3.2 °F at the bottom head location will occur due to the uprate. This is summarized in Table 2.1.5-1 of the EPU application.

Based on the discussion above, the NRC staff finds that the licensee (1) compared the design-basis loads in its license renewal application with the EPU loads, and (2) as appropriate, reanalyzed loads using EPU parameters. Thus, the licensee has demonstrated that the NSSS piping, components, and supports will perform their intended functions under EPU conditions. Furthermore, the staff concludes that the increase in temperature and elevated chemistry has been sufficiently evaluated by the licensee to demonstrate that the uprate conditions have no impact on the ability of the NSSS piping, components, and supports to maintain structural integrity due to the EPU. Therefore, the staff finds this acceptable.

Summary

The NRC staff finds that while the small increase in temperature and elevated chemistry during power uprate conditions at Ginna has a minor effect on RCS component materials, no new failure mechanisms are introduced due to the EPU that challenge RCPB materials. Therefore, the staff concludes that the licensee's activities to maintain chemistry control and an effective inspection program that were accepted by the staff under NUREG-1786 provide an acceptable level of quality and safety. The staff agrees with the licensee's conclusion that the above listed materials will not be adversely effected in a significant manner due to the power uprate.

Based upon the results of its review and the licensee's responses to the staff's RAIs, the staff concludes that the licensee has adequately evaluated the effects of power uprate on the integrity of RCS materials. The NRC staff further concludes that the licensee has demonstrated that the RCS materials will continue to be acceptable following implementation of the proposed power uprate and will continue to meet the requirements of GDC 1, GDC 4, GDC 14, GDC 31, 10 CFR Part 50, Appendix G, and 10 CFR 50.55a. Therefore, the NRC staff finds the proposed power uprate acceptable with respect to RCS materials.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the susceptibility of RCPB materials to known degradation mechanisms and concludes that the licensee has identified appropriate degradation management programs to address the effects of changes in system operating temperature on the integrity of the RCPB materials. The NRC staff further concludes that the licensee has demonstrated that the RCPB materials will continue to be acceptable following implementation of the proposed EPU and will continue to meet the requirements of GDC 1, 4, 14, and 31, 10 CFR Part 50, Appendix G, and 10 CFR 50.55a. Therefore, the NRC staff finds the proposed EPU acceptable with respect to RCPB materials.

2.1.6 Leak-Before-Break (LBB)

Regulatory Evaluation

The LBB analyses provide a means for eliminating from the design basis the dynamic effects of postulated pipe ruptures for a piping system. NRC approval of LBB for a plant permits the licensee (1) to remove protective hardware along the piping system (e.g., pipe whip restraints and jet impingement barriers), and (2) to redesign pipe-connected components, their supports, and their internals. The NRC staff's review of LBB covered (a) direct pipe failure mechanisms (e.g., water hammer, creep damage, erosion, corrosion, fatigue, and environmental conditions); (b) indirect pipe failure mechanisms (e.g., seismic events, system overpressurizations, fire, flooding, missiles, and failures of SSCs in close proximity to the piping); and (c) deterministic fracture mechanics and leak detection methods. The NRC's acceptance criteria for LBB are based on GDC 4, insofar as it allows for exclusion of dynamic effects of postulated pipe ruptures from the design basis. Specific review criteria are contained in draft SRP Section 3.6.3 and other guidance provided in Matrix 1 of RS-001.

Technical Evaluation

The licensee stated that the current structural design basis of Ginna includes the application of LBB methodology to eliminate consideration of the dynamic effects resulting from pipe breaks in the RCS primary loop piping. Section 2.1.6.2 of the licensee's submittal describes the analyses and evaluations performed to demonstrate that the elimination of these breaks continues to be justified at the operating conditions associated with the EPU.

According to the licensee, Westinghouse performed analyses for LBB of primary loop piping and RCP pump casings in 2002 for the Ginna license renewal application. The results of the 2002 analysis were documented in WCAP-15837, "Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the R.E. Ginna Nuclear Power Plant for the License Renewal Program, April 2002." The subject WCAP was accepted by the staff under NUREG-1786, in Section 4.7.7 of the SER.

To support the EPU, the licensee evaluated the impact of the EPU on the conclusions reached in the LBB analysis approved by the staff and concluded that the primary loop piping LBB and RCP casings analyses remain valid for EPU conditions based on the following results:

C Leak Rate – A margin of 10.0 exists between the calculated leak rate from the leakage flaw and the leak detection capability of 0.25 gpm.

C Flaw Size – A margin of 2.0 or more exists between the critical flaw size and the leakage flaw size.

C Loads – A margin of 1.0 (using faulted load combinations by absolute summation method) or %2 exists.

The LBB acceptance criteria and the recommended margins stated in draft SRP Section 3.6.3 are as follows:

- Margin of 10 on leak rate
- Margin of 2.0 on flaw size
- Margin of 1.0 on loads (using faulted load combinations by the absolute summation method)

The evaluation results showed the following at all the critical locations: a margin of 10 exists between the calculated leak rate from the leakage flaw and leak detection capability of 1 gpm; a margin of 2.0 or more exists between the critical flaw size and the flaw size having a leak rate of 10 gpm (the leakage flaw); and a margin of 1.0 on loads exists using faulted load combinations by the absolute summation method. The evaluation results showed that the LBB conclusions provided in WCAP-15837 remain unchanged under power uprate conditions.

The licensee determined that the LBB acceptance criteria are satisfied for the primary loop piping under power uprate conditions. All the recommended margins are satisfied and the conclusions shown in WCAP-15837 remain valid. Therefore, the licensee concluded that the dynamic effects of RCS primary loop pipe breaks need not be considered in the structural design basis at the power uprate conditions.

The NRC staff reviewed the information submitted by the licensee concerning the potential impact of the proposed power uprate on the acceptability of the LBB status of the RCS piping. The primary system pressure, primary system temperature, material properties, and design-basis safe shutdown earthquake (SSE) loadings are the parameters that could have a significant impact on the facility's LBB evaluation. However, the licensee demonstrated that the LBB acceptance criteria and the recommended margins, based on the draft SRP Section 3.6.3, would be maintained under power uprate conditions. Therefore, the staff concludes that the changes to the LBB evaluation for this piping resulting from the proposed power uprate will not alter the staff's previous conclusions stated in NUREG-1786, Section 4.7.7 of the SER. The staff concludes that, per the provisions of 10 CFR Part 50, Appendix A, GDC 4, the dynamic effects from postulated breaks of the RCS piping may continue to be excluded from the licensing basis of the facility for post-power uprate conditions. The NRC staff further concludes that the licensee has demonstrated that the LBB analyses will continue to be valid following implementation of the proposed power uprate and that piping for which the licensee credits LBB will continue to meet the requirements of GDC 4. Therefore, the NRC staff finds the proposed power uprate acceptable with respect to LBB.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the LBB analysis for the plant and concludes that the licensee has adequately addressed changes in primary system pressure and temperature and their effects on the LBB analyses. The NRC staff further concludes that the licensee has demonstrated that the LBB analyses will continue to be valid following implementation of the proposed EPU and that piping for which the licensee credits LBB will continue to meet the requirements of GDC 4. Therefore, the NRC staff finds the proposed EPU acceptable with respect to LBB.

2.1.7 Protective Coating Systems (Paints) - Organic Materials

Regulatory Evaluation

Organic paints are protective coating systems that provide a means for protecting the surfaces of facilities and equipment from corrosion and contamination from radionuclides and also provide wear protection during plant operation and maintenance activities. The NRC staff reviews protective coating systems and other organic materials used inside the containment for their suitability for and stability under DBA conditions, considering radiation and chemical effects. The NRC's acceptance criteria for protective coating systems are based on: (1) 10 CFR Part 50, Appendix B, which provides quality assurance requirements for the design, fabrication, and construction of safety-related structures, systems, and components; and (2) RG 1.54, Revision 1, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants," for application and performance monitoring guidance of coatings in nuclear power plants. Specific review criteria are contained in SRP Section 6.1.2, "Protective Coating Systems (Paints) - Organic Materials."

Technical Evaluation

Ginna has coatings systems inside containment, and the licensee provided a summary of its evaluation of the effects of radiation and chemical effects on these coatings under design-basis LOCA conditions. The application of the original coatings pre-dates RG 1.54 and American National Standards Institute (ANSI) Standard N101.4, "Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities," dated November 1972. The licensee, therefore, used Westinghouse and plant specifications to procure and apply the containment coatings consistent with the quality assurance requirements of 10 CFR Part 50, Appendix B.

The licensee stated that the Ginna Quality Assurance Program for Station Operation uses the quality assurance requirements of 10 CFR Part 50, Appendix B for new coatings and configuration changes to existing coatings which have the potential to affect a safety-related function. All coating systems are inspected and their condition monitored to determine when appropriate maintenance actions are needed. Corrective actions are performed in accordance with 10 CFR Part 50, Appendix B according to the technical and quality requirements for the Service Level 1 coatings program. In 1998, the NRC accepted the licensee's response to GL 98-04, which requested information about programs to ensure Service Level 1 protective coatings inside containment do not detach from the substrate during a design-basis LOCA and potentially interfere with operation of safety systems.

The licensee compared expected EPU environmental conditions to the qualification conditions for the coatings. According to the licensee’s analysis, containment pressure, total integrated radiation dose, and containment spray pH for EPU conditions are bounded by qualification conditions and therefore do not affect coating qualification. The licensee reached the same conclusion for the post-accident temperature increase. The post-accident temperature peak (286 EF) and 30-day temperature (152 EF) are bounded by the industry tests of the predominant coating system. This system consists of Carbozinc-11 primer and Phenoline 305 top coat, which were tested to an accident peak temperature of 320 EF, a 60-day temperature of 150-175 EF, and two accident transients without deterioration or loss of adhesion.

In a letter dated November 10, 2005, the NRC staff asked the licensee if these evaluations are bounding for other coating systems at EPU conditions. In a letter dated December 22, 2005, the licensee responded that virtually all of the coatings in the Ginna containment - including inorganic zincs, modified phenolics, and epoxy coatings - are resistant to the post-accident environment, including EPU conditions. The only condition expected to be more severe as a result of the EPU is the radiation increase, but the qualification test level of 10^9 rads is higher than the calculated post-accident levels of 10^6 to 10^7 rads. The licensee also explained, in response to a staff request, that the term “coating configuration changes” used in the licensing report refers to updated formulations comparable to previously installed coatings.

The licensee noted that small quantities of unqualified coatings are accounted for in the debris source term for containment sump blockage evaluations. In response to a related question from the staff, the licensee replied in its December 22, 2005, letter that the potential clogging of containment emergency sumps (resolution to GL 2004-02) will address EPU conditions. With respect to coatings maintenance, the staff requested additional information on the requirements for removing and replacing degraded paint, and any effects of EPU conditions on these requirements. The licensee replied that coating conditions are included as part of visual inspections during each refueling outage and general walkdowns by personnel from various plant departments. Loose coatings are removed, localized degraded areas are evaluated and scheduled for repair or replacement, and repair/replacement is performed later according to the evaluation. The licensee determined there was no effect of the EPU on these activities.

In addition to paints, other organic material such as cable insulation can be exposed to DBA conditions which could degrade the material and generate organic gases and hydrogen. In response to the staff’s RAI on this topic, the licensee replied in its December 22, 2005, letter that EPU post-accident design basis conditions are bounded by qualification testing levels for both coatings and organic equipment. Consequently, the licensee concluded insignificant amounts of organic hydrogen and organic gases would be generated under DBA conditions.

Conclusion

The NRC staff has reviewed the licensee’s evaluation of the effects of the proposed EPU on protective coating systems and other organic materials and concludes that the licensee has appropriately addressed the impact of changes in conditions following a design-basis LOCA and their effects on these organic materials. The NRC staff further concludes that the licensee has demonstrated that conditions following the implementation of the proposed EPU will continue to be bounded by qualification test conditions. Therefore, the NRC staff finds the proposed EPU acceptable with respect to protective coating systems and other organic materials.

2.1.8 Flow-Accelerated Corrosion

Regulatory Evaluation

Flow accelerated corrosion (FAC) is a corrosion mechanism occurring in carbon steel components exposed to single-phase or two-phase water flow. Components made from stainless steel are immune to FAC, and FAC is significantly reduced in components containing even small amounts of chromium or molybdenum. The rates of material loss due to FAC depend on flow velocity, fluid temperature, steam quality, oxygen content, and pH. During plant operation, it is not normally possible to maintain these parameters in a regime that minimizes FAC, and loss of material by FAC can therefore occur. The NRC staff reviewed the effects of the proposed EPU on FAC and the adequacy of the licensee's FAC program to predict the rate of component thinning so that repair or replacement of damaged components could be made before reaching a critical thickness. The licensee's FAC program consists of predicting loss of material using the EPRI's CHECWORKS computer code, visual inspection, and volumetric examination of the affected components. The NRC's acceptance criteria are based on the structural evaluation of the minimum acceptable wall thickness for the components undergoing degradation by FAC.

Technical Evaluation

The FAC program at Ginna is a subprogram of the licensee's broader Erosion/Corrosion (E/C) Program. It consists of predicting loss of material using the EPRI CHECWORKS computer code, visual inspection, and volumetric inspection of the affected components. The FAC program is based on NUREG-1344, "Erosion/Corrosion-Induced Pipe Wall Thinning in U.S. Nuclear Power Plants," GL 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning," and EPRI Report NSAC-202L-R2, "Recommendations for an Effective Flow-Accelerated Corrosion Program." The goal of the FAC program is to ensure FAC does not result in unacceptable degradation of structural integrity of carbon steel piping systems.

The licensee's discussion of the FAC program was part of a broader discussion on the E/C program evaluation. Piping, pressure vessels, and storage tanks containing both single-phase and two-phase fluids are within the scope of the E/C program. Piping and equipment may be excluded from the E/C program based on piping material, fluid contained in the piping system, system usage, system operating conditions, industry and plant experience, and pipe size. Large-bore piping systems in the FAC program include feedwater, condensate, heater drains, moisture separator reheater (MSR) drains, SG blowdown, extraction steam, and gland steam. Some small-bore piping systems (between 3/4-inch and 2-inch nominal diameter) are included in the FAC program, but most are monitored in the small-bore E/C program.

The licensee stated that the FAC program contains criteria for the following: inspection frequency, acceptance, inspection/expansion, repair/replacement, and corrective actions. The CHECWORKS program is used to model and evaluate piping systems in order to focus inspection resources on the locations most likely to experience degradation. This plant-specific CHECWORKS model provides quantitative estimates of erosion-corrosion rates and times to reach the minimum allowable wall thickness. Inspection locations are based on the CHECWORKS analysis, experience at Ginna and other plants, engineering judgment, sample expansion during an inspection, and re-inspection based on the previously measured thinning rate. Ultrasonic testing (UT) is the primary non-destructive method used to measure thickness.

The licensee evaluated the potential for increased FAC based on changes in temperature, pressure, flow rate, and steam quality due to power uprate conditions. For example, condensate/feedwater outlet nozzles from the 2A/2B feedwater heaters and inlet nozzles from the 3A/3B feedwater heaters are being added to the FAC program based on operating temperature increasing to above 212 EF at EPU conditions. This is the temperature identified by EPRI as the lower threshold for FAC in single-phase (all-liquid) systems. Similarly, certain feedwater heater condensate piping will be added to the FAC program because the temperature will increase from about 208 EF at current conditions to 217 EF at EPU conditions. A table provided in the licensing report compares the CHECWORKS-calculated corrosion rates at present full-power conditions to those at EPU conditions for a representative sample of components susceptible to FAC. The table indicates FAC rates will increase by as much as 24%. A second table in the licensing report provides, for the same group of components, the difference between previous thickness measurements and predictions.

In a December 22, 2005, letter responding to questions from the NRC staff, the licensee described the actions taken for a component judged susceptible to FAC but inaccessible for inspection. These components are first evaluated analytically using the EPRI CHECWORKS code. The analytical predictions are then compared to the measured corrosion rates of components (usually adjacent) that have similar geometry and fluid conditions. If the analytical results are conservative compared to the measured corrosion rate, they are used to trend the thickness of the un-inspected component. If the analytical results are less conservative then the measured results for the adjacent component, the measured thinning rate is used to trend the un-inspected component. This process is supplemented with remote internal visual inspection if there is an opportunity.

Also in the December 22 response, the licensee discussed an example of a component replacement resulting from FAC. During the 2005 refueling outage, piping in the extraction steam line to Feedwater Heater 4B was replaced due to localized thinning downstream of a welded joint. The decision to replace the piping was based on previous inspection results and extrapolation of the corrosion rate as calculated by the CHECWORKS program. To prevent recurrence, the original A106 carbon steel piping was replaced with chromium-molybdenum (Cr-Mo) steel, and a Cr-Mo weld overlay was applied to the heater inlet nozzle. Based on this experience, the licensee is scheduled to replace the corresponding piping on the 4A Feedwater Heater during the next (2006) refueling outage.

Plant modifications due to EPU may increase the FAC susceptibility of new components or existing components. The licensee stated that the effect of modifications on the E/C program will be addressed as part of the plant change process. The components will be evaluated according to the E/C program inclusion/exclusion criteria to determine if they will be subject to the program.

In the licensing report and in the December 22, 2005, letter responding to staff requests, the licensee described the process for evaluating inspection results to determine repair and replacement needs. The measured component wall thickness is compared to the nominal wall thickness. If the measured thickness is more than 87.5% of the nominal wall thickness the component is acceptable for continued service. If the measured thickness is less than a pre-determined, outage-specific minimum thickness, an evaluation is performed to determine if the structural requirements are met. The steps of this evaluation are described below. The pre-determined thickness is calculated by adding a corrosion allowance to the ASME Code-calculated minimum allowable thickness. The corrosion allowance is the amount of thickness loss anticipated during operation until the subsequent refueling outage. The corrosion allowance is determined from corrosion rates calculated using CHECWORKS.

The first step of the structural integrity evaluation is to use the expected corrosion rate to predict the wall thickness at the end of the next operating interval. Then, if this predicted thickness is less than or equal to 30% of the nominal wall thickness the component must be repaired or replaced, and the inspection scope is expanded. If the predicted thickness of a component is less than or equal to 87.5% and greater than 30% of the nominal wall thickness, the structural evaluation is continued in more detail to determine if continued service is acceptable. In the December 22, 2005 letter, the licensee explained that these are evaluations of the actual component stresses at the location of concern. These evaluations may show that the minimum required component thickness for the actual stress condition may be lower than that initially calculated based on bounding assumptions. In such a case, the licensee may defer component repair or replacement. If the evaluation shows that the minimum allowable thickness cannot be significantly reduced, then the licensee repairs or replaces the component.

Regarding the small-bore E/C program, the licensee clarified in its December 22, 2005, letter how components are selected for the program and the basis for repair replacement decisions. The NRC staff requested clarification because EPRI NSAC-202L-R2 guidelines for FAC programs recommend that predicted corrosion rates (e.g. CHECWORKS model predictions) not be used for repair/replacement decisions on small-bore components unless certain conditions are met. The licensee explained that decisions to repair or replace components in the small-bore E/C program are based only on corrosion rates calculated from thickness measurements. Components are included in the small-bore E/C program based on a review of industry experience, operating experience at Ginna, and the judgment of the Ginna E/C Engineer. A typical refueling outage includes non-destructive examination of 120 small-bore components. The licensee further clarified that some small-bore components are susceptible to FAC and are included in the Ginna CHECWORKS model (e.g., the 1-inch piping associated with the moisture separator reheater 4th pass drain lines). For these components, repair and replacement decisions are based on corrosion rates from thickness measurements as well as from CHECWORKS predictions.

Also in response to a question from the NRC staff, the licensee explained in the December 22, 2005, letter that plant piping and tubing less than 3/4-inch in diameter is generally excluded from the small-bore program because these lines create a low level of safety and operational concern. The licensee further stated that this exclusion is supported by inspections of opportunity and plant operating experience.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effect of the proposed EPU on the FAC analysis for the plant and concludes the licensee has adequately addressed the impact of changes in plant operating conditions. Further, the NRC staff concludes the licensee has demonstrated the updated analyses will predict the loss of material by FAC and will ensure timely repair or replacement of degraded components following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to FAC.

2.1.9 SG Tube Inservice Inspection

Regulatory Evaluation

SG tubes constitute a large part of the RCPB. The NRC staff's review in this area covered the effects of changes in operating parameters resulting from the proposed power uprate on the design and operation of the SGs. The NRC's acceptance criteria are based on RG 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes," RG 1.83, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes," and SRP Sections 5.4.2.1, "Steam Generator Materials," and 5.4.2.2, "Steam Generator Tube Inservice Inspection." RG 1.121 describes an acceptable method for establishing the limit on the extent of degradation in the tubes, beyond which the tubes shall be removed from service. The level of acceptable degradation is referred to as the plugging or repair limit.

Technical Evaluation

The replacement U-tube SGs at Ginna were fabricated by Babcock and Wilcox International (B&W). Each SG contains 4,765 thermally-treated Alloy 690 (Alloy 690TT) tubes, which have a nominal outside diameter of 0.750 inch and nominal wall thickness of 0.043 inch. The tubes are supported by Type 410S stainless steel lattice bars and U-bend flat bars. Each tube was hydraulically expanded into the tubesheet through the full tubesheet thickness, and the tube ends were welded to the Alloy 600 weld overlay on the primary side of the tubesheet.

The licensee implements the criteria of Nuclear Energy Institute (NEI) Report NEI 97-06 for degradation prevention, inspection, evaluation, repair, and leakage monitoring. As a result of the power uprate, the licensee expects the following SG process parameters to change: temperatures, steam pressure, steam and feedwater flows, void fraction distributions, and circulation ratio.

The anticipated changes in the SG operational parameters may affect the initiation and growth rates of degradation modes. In order to ensure the inspection scope and techniques used will address all identified and potential degradation mechanisms, the licensee performs a degradation assessment prior to tube inspections.

In response to a question from the NRC staff, the licensee confirmed, in a letter dated December 22, 2005, that the 40% through-wall tube plugging limit remains appropriate for EPU conditions according to RG 1.121 analysis. The EPU will reduce the primary-to-secondary pressure differential (ΔP) during normal operation because the steam pressure will increase to about 798 psia from the current value of 770 psia. Under these conditions, maintaining factor of safety of 3.0 against tube burst during normal operation remains the limiting criterion, and the licensee stated this criterion would continue to support the 40% plugging limit. The increase in the hot-leg primary water temperature from about 604 EF to 611 EF will theoretically decrease the initiation time and increase the growth rate for PWSCC based on experience with less corrosion resistant tube materials. However, because the tubes are Alloy 690TT and the hot-leg temperature will continue to be within the range of other operating plants, the NRC staff expects all degradation will continue to be managed effectively by the licensee's existing ISI program.

The NRC staff notes that the licensee is authorized by the Ginna TSs to install sleeves as a repair method, but no analysis was provided for sleeving at EPU conditions. Despite this concern, there are currently no sleeves installed in the Ginna SGs, nor is it likely there will be a need to install sleeves in the near term given the present condition of the SGs. Furthermore, the licensee stated that it would be submitting an amendment application adopting the NRC-approved Revision 4 of the TS Task Force (TSTF) Change TSTF-449, “Steam Generator Tube Integrity.” In that amendment application, the licensee stated that it will remove the references to the use of sleeves from the TSs. Therefore, the NRC staff finds this aspect of the submittal acceptable.

Each SG had one tube removed from service (plugged) due to manufacturing flaws identified during the preservice inspection. No service-related tube degradation has been detected; however, four tubes were removed from service (plugged and stabilized) in the “B” SG during the 2005 refueling outage due to a small foreign object lodged between two tubes at an elevation approximately 20.5 inches above the cold-leg tubesheet. Bobbin and rotating probe eddy current testing (ECT) detected no degradation from the object, which is approximately 0.25 inch x 0.50 inch x 0.04 inch in size (according to the licensee’s July 1, 2005, inspection report for the 2005 outage). In response to a staff request, the licensee confirmed in the December 22, 2005, letter that loose parts are included in operational assessments to determine the acceptable operating interval before the subsequent inspection. The licensee will be making these assessments a TS requirement by adopting Revision 4 of the Standard TSs for SG tube integrity.

In response to an RAI from the NRC staff, the licensee stated in its December 22, 2005, letter that the RSG vendor performed a structural evaluation and concluded the SGs will continue to satisfy ASME Code structural requirements for Design, Test, and Level A, B, C, and D service conditions. The licensee stated this evaluation also affirmed the validity of the original non-ductile fracture analysis. In the same letter, in response to a request from the NRC staff, the licensee also confirmed that the evaluation of the effect of EPU conditions on the SGs addresses the current condition of the SGs. No modifications have been made to the as-built SG configuration, and the range of tube plugging in the analyses (0% to 10%) bounds the current plugging level (one tube in SG “A” and five tubes in SG “B”). The staff also asked if 10% tube plugging is equal to or greater than the plugging level assumed in the accident

analysis currently for Ginna. In its letter dated December 22, 2005, the licensee stated the currently approved accident analysis assumes 15% plugging, but 10% was considered to be a conservative end-of-life upper bound plugging level for SGs with Alloy 690TT tubes. In addition, the licensee noted the expected operating temperatures are bounded by those at other plants with Alloy 690TT tubes. In a telephone call on January 30, 2006, the licensee further explained that, as part of the implementation upon approval of the EPU amendment, it will be modifying the UFSAR (Reference 20) to indicate that the EPU conditions assume a maximum of 10% tube plugging.

Responding to questions from the staff about materials specifications and compatibility, the licensee confirmed in its December 22, 2005, letter that the SG closure bolting (manway, handhole, and inspection port studs) are made from SA-193 Gr. B7 material, in compliance with Sections II and III of the ASME Code. This material is listed in the SRP Section 5.4.2.1 for SG bolting material and is, therefore, acceptable to the staff. The licensee also stated the Alloy 690TT tube material would be compatible with the primary and secondary coolant at EPU conditions because no changes in chemistry are planned and the EPU evaluations were performed for a range of reactor coolant system hot-leg and cold-leg temperatures that bound the anticipated service conditions. The use of Alloy 690TT tube material is acceptable to the staff because this material meets the criteria of SRP Section 5.4.2.1. In addition, the licensee controls primary and secondary water chemistry according to EPRI guidelines, operating experience has shown Alloy 690 tubing is compatible with these chemistry and temperature conditions, and the licensee's inservice inspection program will be capable of managing any degradation that occurs.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on SG tube integrity and concludes the licensee has adequately addressed the impact of changes in plant operating conditions. Since it did not provided an analysis for tube sleeving at EPU conditions, the licensee has committed to remove references to tube sleeving from the TSs. This will be done when it submits a license amendment request to adopt the NRC-approved Revision 4 of TSTF-449.

2.1.10 SG Blowdown System

Regulatory Evaluation

Control of secondary-side water chemistry is important for preventing degradation of SG tubes. The SG blowdown system (SGBS) provides a means for removing SG secondary-side impurities and thus, assists in maintaining acceptable secondary-side water chemistry in the SGs. The design basis of the SGBS includes consideration of expected design flows for all modes of operation. The NRC staff's review covered the ability of the SGBS to remove particulate and dissolved impurities from the SG secondary-side during normal operation, including condenser in-leakage and primary-to-secondary leakage. The NRC's acceptance criteria for the SGBS are based on GDC 14, "Reactor coolant pressure boundary," insofar as it requires that the RCPB be designed so as to have an extremely low probability of abnormal leakage, of rapidly propagating fracture, and of gross rupture. Specific review criteria are contained in SRP Section 10.4.8, "Steam Generator Blowdown System (PWR)."

Technical Evaluation

The SGBS has the following design functions: (1) blow down fluid at a continuous rate for SG chemistry control; (2) blow down fluid at a surge rate to recover from abnormal chemistry; (3) recover the blowdown water and its heat capacity; and (4) provide for containment isolation of blowdown lines. The licensee evaluated the effects of EPU conditions on the ability of the system to perform these intended functions during normal operation and operational occurrences at EPU conditions. According to the licensee, the SGBS was operated at about 100 gallons per minute (gpm) per SG for most of its history, but the present operating condition is about 40 to 80 gpm per SG. The flow rate was reduced because a portion of blowdown flow is no longer directed to the condensate polishing demineralizer except during unusual accumulations of impurities.

The licensee reported that the increased steam and feedwater flow rates at EPU conditions would not significantly affect the concentration of impurities nor increase the effect of the impurities on the SGs. Therefore, the blowdown rate is expected to be maintained in the historical range of 40 to 100 gpm. The system is also designed for surges of 3 to 5 minutes, about once per week. In response to a question from the NRC staff, the licensee explained, in a letter dated December 22, 2005, that the piping for the SG "A" blowdown loop, including a cross-tie designed to carry the flow from both SGs during maintenance of flow-control valves, has a short-term surge capability of 300 gpm. The piping inside containment for the SG "B" blowdown loop has a short-term surge capability of 150 gpm. In addition, the licensee stated in the December 22, 2005, response that Ginna operating procedures limit the total blowdown flow to 60 gpm per SG when the SG blowdown cross-tie valve is open. Operating procedures do not allow the blowdown flow to exceed 125 gpm per SG in any mode of operation. In summary, the flow rate through a single SG loop will remain at 40 to 100 gpm, and the minimum design value is 150 gpm (loop B). The maximum flow rate through the combined portion will not exceed 120 gpm, and the design value is 300 gpm.

The licensee stated the design values of 557 EF and 1085 psig remain bounding for EPU conditions since they are based on zero-load operating conditions, which do not change as a result of the EPU. The licensee also concluded that the air-operated isolation valves, which are designed to close for containment isolation following accidents, will continue to meet their design function because the maximum blowdown flow rates through and pressures on the valves do not exceed the existing design capabilities. To address the possibility of increased corrosion rates, the SGBS will continue to be monitored by the E/C Program. Since the temperature, pressure, and flow rates at EPU conditions remain bounded by design values, and since any significant increase in corrosion rate is designed to be detected by the E/C program, the staff finds the proposed EPU acceptable for the SGBS

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the SGBS and concludes that the licensee has adequately addressed changes in system flow and impurity levels and their effects on the SGBS. The NRC staff further concludes that the licensee has demonstrated that the SGBS will continue to be acceptable and will continue to meet the requirements of GDC 14 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the SGBS.

2.1.11 Chemical and Volume Control System

Regulatory Evaluation

The Chemical and Volume Control System (CVCS) and Boron Recovery System (BRS) provide means for (1) maintaining water inventory and quality in the RCS, (2) supplying seal-water flow to the reactor coolant pumps and pressurizer auxiliary spray, (3) controlling the boron neutron absorber concentration in the reactor coolant, (4) controlling the primary-water chemistry and reducing coolant radioactivity level, and (5) providing recycled coolant for demineralized water makeup for normal operation. The NRC's acceptance criteria are based on: (1) GDC 14, insofar as it requires that the RCPB be designed so as to have an extremely low probability of abnormal leakage, of rapidly propagating fracture, and of gross rupture; and (2) GDC 29, "Protection against anticipated operational occurrences," insofar as it requires that the reactivity control systems be designed to assure an extremely high probability of accomplishing their functions in the event of condenser in-leakage or primary-to-secondary leakage. Specific review criteria are contained in SRP Section 9.3.4.

Technical Evaluation

Meeting the requirements of GDC 14 enhances plant safety by providing assurance that the probability of corrosion-induced failure of the reactor coolant pressure boundary will be minimized, thereby maintaining the integrity of the reactor coolant pressure boundary. Meeting the requirements of GDC 29 enhances plant safety by assuring the reactivity control aspects of the CVCS will have a high probability of injecting sufficient negative reactivity to prevent damage to the fuel matrix and cladding during anticipated operational occurrences. The NRC staff examined whether changes in operating conditions due to the power uprate would affect the ability of the CVCS components to continue performing their intended functions within design limits.

The CVCS at Ginna is described in UFSAR Section 9.3.4. The system design functions are performed by maintaining a continuous feed-and-bleed between the RCS and the CVCS. Water is let down from the RCS through a regenerative heat exchanger (HX), and pressure is reduced by orifices. The temperature is reduced further in a non-regenerative HX. Water is returned to the RCS by the charging system, which also provides seal injection flow to the reactor coolant pumps. The chemistry of the letdown flow can be altered by passing the flow through demineralizers. Solids are removed by mechanical filters and dissolved gases are removed in the volume control tank. A reactor makeup portion of the CVCS is used to control boric acid concentration as required for reactivity control. In addition to the functions listed above, the Ginna CVCS also supports containment isolation through piping segments that penetrate the containment.

The licensee evaluated the potential effects of the increase in core power and the allowable range of RCS full-load design temperatures on the functionality of the CVCS subsystems. For heat exchangers, because the no-load temperature (547 EF) will not change and the RCS T_{cold} remains below the no-load temperature, the licensee expects continued acceptable performance and the same charging and letdown flows with no plant changes required. The small temperature changes will likewise have no effect on the performance of piping and valves.

The licensee noted some changes due to the power level increase. For example, the EPU is expected to increase the amount of boron needed for negative reactivity control, but this increase is within the present capabilities of the system and would be addressed during the reload SE for each reload cycle. There is also a potential increase in crud buildup at EPU conditions, but the corresponding increase in charging and letdown flow for RCS purification and cleanup is within the present capabilities of the system. These changes are acceptable to the staff because the boron and flow rate requirements at EPU conditions remain within the system capabilities. In addition, the periodic re-evaluation ensures system functionality at the increased power level. The licensee expects the amount of N-16 activity in the letdown and excess letdown lines to increase by an amount proportional to the reactor power level increase, but there will continue to be adequate decay of N-16 before the letdown fluid leaves the containment building. The licensee evaluated the increase in the amount of N-16 and found it to be acceptable. The NRC staff finds this acceptable because the licensee will continue to manage worker exposure through plant access restrictions and exposure monitoring consistent with 10 CFR Part 20.

<u>Conclusion</u>

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the CVCS and concludes that the licensee has adequately addressed changes in the temperature of the reactor coolant and their effects on the CVCS. The NRC staff further concludes that the licensee has demonstrated that the CVCS will continue to perform all functions acceptably and will continue to meet the requirements of GDC 14 and GDC 29 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the CVCS.

2.2 Mechanical and Civil Engineering

2.2.1 Pipe Rupture Locations and Associated Dynamic Effects

Regulatory Evaluation

SSCs important to safety could be impacted by the pipe-whip dynamic effects of a pipe rupture. The NRC staff conducted a review of pipe rupture analyses to ensure that SSCs important to safety are adequately protected from the effects of pipe ruptures. The NRC staff's review covered: (1) the implementation of criteria for defining pipe break and crack locations and configurations, (2) the implementation of criteria dealing with special features, such as augmented ISI programs or the use of special protective devices such as pipe-whip restraints, (3) pipe-whip dynamic analyses and results, including the jet thrust and impingement forcing functions and pipe-whip dynamic effects, and (4) the design adequacy of supports for SSCs provided to ensure that the intended design functions of the SSCs will not be impaired to an unacceptable level as a result of pipe-whip or jet impingement loadings. The NRC staff's review focused on the effects that the proposed EPU may have on items (1) thru (4) above. The NRC's acceptance criteria are based on GDC 4, which requires SSCs important to safety to be designed to accommodate the dynamic effects of a postulated pipe rupture. Specific review criteria are contained in SRP Section 3.6.2.

Technical Evaluation

The Ginna design basis for protection against the dynamic effects associated with the postulated rupture of piping in containment implemented the design criteria of the Atomic Industrial Forum developed in the early 1960s. In the late 1970s, the NRC initiated the Systematic Evaluation Program (SEP) to review the designs of older operating nuclear power plants to reconfirm and document their safety. The licensee's evaluation of piping inside and outside of containment in accordance with SEP Topics III-5.A and III-5.B was shown to meet the requirements of GDC 4 with several modifications and an augmented in-service inspection program. Pipe ruptures were postulated at arbitrary intermediate locations in addition to terminal ends and high stress locations as then required by Branch Technical Position (BTP) MEB 3-1 of SRP 3.6.2. Pipe whip restraints and jet impingement shields were installed as necessary to mitigate the effects of arbitrary intermediate pipe ruptures. The results of the staff's SEP review of Ginna were documented in NUREG-0821. GL 87-11 revised BTP MEB 3-1 to eliminate the requirement to postulate arbitrary intermediate pipe ruptures and permitted the elimination of pipe whip restraints and jet impingement shields to mitigate the effects of arbitrary intermediate pipe ruptures. Ginna Station subsequently implemented the LBB guidance documented in GDC 4 to demonstrate that certain high energy lines in containment were designed, constructed and analyzed to have a negligible probability of failure as part of their design basis. Based on the staff’s evaluation of LBB documented in Section 2.1.6 of this SER, LBB is applicable for the RCS main loop piping, the pressurizer surge line, and the accumulator and RHR lines, which exempts these large diameter breaks from consideration of dynamic effects analysis. In addition to the evaluations documented in Ginna Station's UFSAR, Ginna Station's pipe rupture components were evaluated for License renewal. System and system component materials of construction, operating history and programs used to manage aging effects are documented in NUREG-1786.

To evaluate changes to the design basis due to the proposed EPU, the licensee evaluated postulated pipe breaks inside and outside containment with respect to the acceptance criteria documented in GDC 4 and the review criteria documented in SRP Section 3.6.2. Pipe breaks in containment not credited with LBB in the mechanical design basis of the RCS are all less than 10-inch primary, and secondary side branch line breaks interfacing with the RCS. Ginna Station reviewed the applicable break locations for the main coolant piping, the pressurizer, the surge line, the RV, the SGs and the reactor coolant pumps (RCPs). For balance-of-plant piping, changes to piping system stress levels resulting from EPU were reconciled with existing pipe rupture postulation criteria. The NRC staff finds that the licensee's evaluations consisted of:

- The implementation of criteria for defining pipe break and crack locations and configurations.

- The implementation of criteria dealing with special features, such as augmented in-service inspection programs or the use of special protective devices such as pipe-whip restraints.

- Pipe-whip dynamic analyses and results, including the jet thrust and impingement forcing functions and pipe-whip dynamic effects.

- The design adequacy of supports for SSCs provided to ensure that the design functions of the SSCs will not be impaired to an unacceptable level as a result of pipe-whip or jet impingement loadings.

Based on the above evaluations, Ginna Station concluded that the design basis for the postulated rupture of piping both inside and outside containment documented in UFSAR Sections 3.6.1 and 3.6.2 remains valid for EPU. The staff finds the scope and analysis methodology of the licensee's evaluation to be acceptable in accordance with SRP Section 3.6.2.

Conclusion

The NRC staff has reviewed the licensee’s evaluations related to determinations of rupture locations and associated dynamic effects and concludes that the licensee has adequately addressed the effects of the proposed EPU on them. The NRC staff further concludes that the licensee has demonstrated that SSCs important to safety will continue to meet the requirements of GDC 4 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the determination of rupture locations and dynamic effects associated with the postulated rupture of piping.

2.2.2 Pressure-Retaining Components and Component Supports

Regulatory Evaluation

The NRC staff has reviewed the structural integrity of pressure-retaining components (and their supports) designed in accordance with the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), Section III, Division 1, and GDCs 1, 2, 4, 14, and 15. The NRC staff’s review focused on the effects of the proposed EPU on the design input parameters and the design-basis loads and load combinations for normal operating, upset, emergency, and faulted conditions. The NRC staff’s review covered (1) the analyses of flow-induced vibration and (2) the analytical methodologies, assumptions, ASME Code editions, and computer programs used for these analyses. The NRC staff’s review also included a comparison of the resulting stresses and cumulative fatigue usage factors (CUFs) against the code-allowable limits. The NRC’s acceptance criteria are based on (1) 10 CFR 50.55a and GDC 1, insofar as they require that SSCs important to safety be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC 2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions; (3) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (4) GDC 14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture; and (5) GDC 15, insofar as it requires that the RCS be designed with margin sufficient to ensure that the design conditions of the RCPB are not exceeded during any condition of normal operation. Specific review criteria are contained in SRP Sections 3.9.1, 3.9.2, 3.9.3, and 5.2.1.1; and other guidance provided in Matrix 2 of RS-001.

Technical Evaluation

a. Nuclear Steam Supply System Piping, Components, and Supports:

The licensee's EPU licensing report indicates that current licensing basis at Ginna for NSSS piping, components, and supports meet the requirements of 10 CFR 50.55(a)(1), and GDC 1, 2, 4, 14, and 15 as documented in Ginna UFSAR Sections 3.1-2, 3.2, 3.5 - 3.9, and 5. The pressure-retaining components and supports at Ginna were also evaluated for license renewal, as documented in NUREG-1786. NUREG-1786 documents the evaluations of systems and components that include materials of construction, operating history, programs used to manage aging effects, and time limited aging analyses (TLAA). A fatigue monitoring program that manages TLAA for metal fatigue was incorporated into the Ginna current licensing basis as part of the staff's approval of the license renewal application.

To evaluate changes to the current licensing basis for NSSS piping, components, and supports due to EPU conditions, the licensee performed evaluations of the existing design-basis analyses for reactor coolant loop (RCL) piping, RCL primary equipment supports, and pressurizer surge line for design parameters that would change with the implementation of EPU. The following analyses were evaluated and reanalyzed by the licensee, where necessary, for EPU parameters:

- RCL loss-of-coolant accident (LOCA) analysis using Loop LOCA hydraulic forces for EPU and the associated Loop LOCA RV motions for EPU

- RCL piping stresses

- RCL displacements at auxiliary piping line connections to the centerline of the RCL at branch nozzle connections and impact on the auxiliary piping systems

- Primary equipment nozzle loads

- RCL piping system LBB loads for LBB evaluation

- Pressurizer surge line piping analysis including the effects of thermal stratification

- RV, SG and RCP support loads

Although not part of the current licensing basis for Ginna, evaluations of flow induced vibration were additionally performed for more susceptible components that would experience a significant flow increase under EPU conditions. To perform the above evaluations for EPU, the following sets of input parameters were used:

- Design parameters for 1817 MWt Power as documented in Table 1.1 of the EPU licensing report

- NSSS design transients documented in Table 2.2.6-1 of the licensing report

- Loop LOCA hydraulic forcing functions discussed in Section 2.8.5.6.3.5 of the licensing report

- Associated Loop LOCA RV motions discussed in Section 2.2.3 of the licensing report

The licensee indicated that ANSI B31.1 1967 Edition including Summer 1973 Addenda is the current licensing basis piping code for the RCL piping system. Since this edition/addenda of the ANSI B31.1 Code does not require a fatigue evaluation of the RCL piping to be performed, and since there is no additional staff requirement to perform a fatigue evaluation of the RCL piping, a fatigue evaluation of the RCL piping was not performed. The licensee notes that NRC Bulletin 88-11 requested that licensees evaluate the pressurizer surge line for fatigue and thermal stratification. The licensee, therefore, evaluated the pressurizer surge line for fatigue and thermal stratification to the requirements of ASME Section III Subsection NB 1986 Edition.

With respect to design parameters for 1817 MWt power, the licensee evaluated the RCL for a lower-bound temperature case (Cases 1 and 2 in Table 1-1 of the licensing report), and an upper-bound temperature case (Cases 3 and 4). These two thermal cases were evaluated to envelope the RCL temperatures and the SG tube plugging data specified in Table 1-1 of the licensing report. With respect to NSSS design transients, the licensee's evaluation of the pressurizer surge line determined that the design transients affected by EPU have an insignificant effect on the results of the pressurizer surge line analysis. The design transients associated with plant heatup and cooldown, which are not affected by EPU, control the fatigue and thermal stratification analysis. With respect to Loop LOCA hydraulic forcing functions forces and associated Loop LOCA RV motions, breaks are no longer postulated for the RCL main loop piping, the pressurizer surge line, and the accumulator and RHR lines due to LBB. For EPU, the Loop LOCA hydraulic forcing function forces and associated Loop LOCA RV motions from the smaller branch line breaks are used; the 3-inch pressurizer spray line on the cold leg, the 2-inch safety injection (SI) line on the hot leg, and the 4-inch upper plenum injection line connections to the vessel. The new analysis showed that the design-basis LOCA hydraulic forcing function forces and the associated Loop LOCA RV motions bound the corresponding Loop LOCA forces and RV motions for EPU with application of LBB.

To review the design parameters that will change due to EPU for impact on the existing RCL piping and auxiliary lines attached to the RCL centerline at the RCL branch nozzle connections, the licensee performed a finite element analysis of the RCL piping using the current licensing basis WESTDYN piping program. The licensee's structural evaluation of the RCL piping for EPU considered the effects of deadweight, thermal expansion, Operating Basis Earthquake (OBE), and Safe Shutdown Earthquake (SSE) loads. The WESTDYN piping model was revised to reflect current as-built conditions and the RSGs. The deadweight analysis for EPU was performed considering the weight of the RCL piping and the primary equipment water weight. The thermal analysis evaluated the RCL piping for the lower-bound and upper-bound temperature cases previously discussed. The seismic analysis for EPU used current licensing basis analysis methods and OBE and SSE input response spectra.

Based on the results of the analyses for EPU conditions, the licensee concludes that there is no adverse effect on the current design basis RCL piping analyses and that the current design basis results documented in Ginna licensing report Section 2.2.2 (Reference 4) remain valid:

- RCL piping stresses for EPU are within allowable limits and meet acceptance criteria as documented in licensing report Table 2.2.2.1-1.

- The applicable RCL piping support loads for the RV and supports, the SGs and supports, and the RCPs and supports remain acceptable for EPU as documented in licensing report Sections 2.2.2.3, 2.2.2.5, and 2.2.2.6.

- RCP and RV nozzle loads for EPU remain acceptable with respect to the allowables defined in the equipment design specifications.

- The applicable RCL piping loads resulting from the licensee's evaluation of the operating temperature ranges documented in licensing report Table 1-1 were provided for evaluation and confirmation of LBB. The evaluation results demonstrated that the LBB conclusions provided in the current LBB analyses remain unchanged for EPU as documented in Section 2.1.6 of the licensing report.

- RCL piping displacements at the intersection of the centerline of the RCL piping and the auxiliary line piping system branch nozzles for EPU are insignificant. Therefore, the current design basis analyses for auxiliary piping systems attached to the RCL remain valid for the EPU conditions.

- For the pressurizer surge line piping, the current design basis analysis of the most critical thermal stratification loading is bounding for EPU operation.

- NSSS piping and components evaluated for flow induced vibration due to EPU were determined to be unaffected due to their heavy construction and small increase in flow.

- The aging evaluations approved by the NRC in the license renewal SER for Ginna (NUREG-1786) for the NSSS piping, components and supports remain valid for EPU. The existing fatigue analysis remains valid for 60 years of operation.

As noted in Section 1.0 of the licensing report, the modifications listed in Table 1.0 are required to be installed for EPU and are scheduled to be installed during the 2006 refueling outage.

After reviewing the licensee's evaluations of NSSS piping, components and supports for EPU as summarized above, the NRC staff finds the scope and analysis methodology of the licensee's review to be acceptable based on the review criteria documented in SRP Sections 3.9.1, 3.9.2, 3.9.3, and 5.2.1.1.

b. Balance-of-Plant Piping, Components, and Supports

The licensee's EPU licensing report indicates that the Ginna current licensing basis for balance-of-plant (BOP) and Non-Class 1 piping and supports inside or outside containment meet the requirements of 10 CFR 50.55(a) and GDC 1, 2, 4, 14, and 15, as documented in Ginna UFSAR Sections 3.2, 3.7, and 3.9. The licensee also evaluated Ginna's BOP and Non-Class 1 components and supports for plant license renewal for the effects of EPU, as described by the NRC staff in NUREG-1786. The licensee evaluated BOP and Non-Class 1 piping and supports for increases in operating temperatures, pressures, and flow rates due to EPU for the nineteen BOP and Non-Class 1 piping and support systems listed in Section 2.2.2.2 of the licensing report. The licensee also evaluated BOP and Non-Class 1 piping systems connected to Class 1 piping to identify any potential impact to BOP and Non-Class 1 piping.

The licensee evaluated piping and support systems for increases in operating temperatures due to EPU, including changes in piping operating temperatures due to revised component cooling and service water heat exchanger requirements. The licensee also resolved inconsistencies in the design basis thermal analysis of the component cooling water system, which did not originally consider plant cooldown operating temperatures. The licensee reanalyzed the component cooling water system for revised plant cooldown operating temperatures due to EPU. With respect to increases in piping system operating pressures, the licensee notes that BOP and Non-Class 1 piping affected by EPU was evaluated for design instead of operating pressures as specified in the piping code of record, ANSI B31.1 1973 Edition including Summer 1973 Addenda. The revised piping system operating pressures due to EPU were considered acceptable without additional review if less than piping system design pressures. The licensee notes that increased flow rates due to EPU occur primarily in piping systems related to the main power cycle. The licensee evaluated the effect of the main steam system increased flow rate due to EPU on steam hammer loads resulting from a turbine stop valve closure event. The licensee also evaluated the effect of feedwater system increased flow rate due to EPU on water hammer loads resulting from a feedwater regulator valve closure / feedwater pump trip. As a result of the licensee's evaluations, nine supports will be upgraded and one support will be added in the main steam system and one support will be upgraded in the main feedwater system before EPU. The licensee noted that the remaining piping systems are not adversely impacted by the EPU.

The licensee's evaluations of turbine cross-over and cross-under piping are summarized in Section 2.5.5.1 of the licensing report. The design pressure of the cross-over piping (moisture separator reheaters to the low pressure turbine inlet) and the cross-under piping (high pressure turbine exhaust to the moisture separator reheaters) is being increased due to EPU. The licensee's evaluations indicate that the maximum piping working pressures are greater than the increased design pressure due to EPU, and that the expansion joints in these reheat lines remain acceptable for EPU. The licensee notes that the cross-under piping is subject to erosion and is monitored as part of Ginna's erosion-corrosion program. Since the EPU flow rate for the cross-under piping is only slightly greater than the current operating flow rate, the rate of erosion/corrosion for the cross-under piping is essentially unchanged for EPU.

The licensee indicates that increased steam flow rate through piping and components may increase piping vibrations. The licensee's vibration monitoring program for EPU is documented in Section 2.12 of the licensing report. The staff's review of the licensee's vibration monitoring program for EPU is documented in Section 2.12 of this SE.

The licensee's evaluation of BOP and Non-Class 1 piping for EPU is summarized in Table 2.2.2.2-1 of the licensing report. The table documents existing stress levels, EPU stress levels, the allowable stresses for the applicable loading conditions, and the resulting design margins (calculated stress divided by allowable stress). The table documents several design margins for EPU that are 0.90 or higher. In response to a staff RAI, the licensee noted that the current design margins for these piping analyses are also 0.90 or higher except for the main steam piping outside containment which has a current design margin less than 0.90. The licensee also indicates that the current seismic design basis for all piping and supports remains valid and is unaffected by EPU.

Based on the licensee's evaluations performed for BOP and Non-Class 1 piping and support systems for increases in operating temperatures, pressures, and flow rates due to EPU, the licensee concludes that:

- Connecting Class 1 pipe does not significantly impact BOP and Non-Class 1 piping for EPU.

- BOP and Non-Class 1 piping remains acceptable for increased operating temperatures, pressures and flow rates due to EPU.

- The main steam system can withstand increased steam hammer loads due to EPU after support modifications.

- The feedwater system can withstand increased water hammer loads due to EPU after a support modification.

- Remaining piping systems are acceptable for potential fluid transients due to EPU.

- Remaining pipe supports are acceptable for EPU.

- Equipment nozzle and containment penetration components are acceptable for EPU.

- Piping systems experiencing higher flow rates due to EPU will be monitored for vibration.

- Main steam and feedwater pipe support modifications do not impact the license renewal system evaluation boundaries

Based on the staff's review of the licensee's evaluations of BOP and Non-Class 1 piping, components and supports for EPU, the NRC staff finds the scope and analysis methodology of the licensee's review to be acceptable based on the review criteria documented in SRP Sections 3.9.1, 3.9.2, 3.9.3, and 5.2.1.1.

With respect to the flow induced vibration at the EPU operation, in its EPU license amendment request and RAI responses dated December 19, 2005, and January 25, 2006, the licensee described the vibration monitoring program to be implemented at Ginna during EPU power ascension and operation. The licensee indicated that plant systems at Ginna with increased flow rate as a result of EPU operation will include the main steam system, extraction steam system, heater drain system, condensate and feedwater system, and gland steam system. The licensee stated that the vibration monitoring program for Ginna during EPU operation will use the guidance provided in ASME OM Code, Part 3. The licensee will incorporate industry operating experience into its vibration monitoring plan at Ginna by increased monitoring of specific components that have experienced vibration-induced problems at other plants.

Prior to EPU implementation, the licensee will walk down systems with increased flow rates to establish a baseline vibration state. The walkdown will identify any locations that warrant continued observation during power ascension. The licensee will conduct the vibration monitoring visually and with more precise displacement instrumentation such as accelerometers, as necessary.

During power ascension, the licensee will perform visual observations and instrumented data recording at 85, 88, 91, 94, 97, and 100% of EPU power levels. Each power level plateau will include a sufficient hold time to perform the visual observations and data recording, and to assess the vibration response in accordance with the acceptance criteria in ASME OM Code, Part 3. Any unacceptable vibration determinations during plant walkdowns or assessments will be addressed by the licensee. Also, during the walkdowns at each power level plateau, licensee engineers will be alert for any thermal expansion issues with plant piping systems.

As further discussed in Section 2.12 of this SE, the NRC staff considers the vibration monitoring program being established for EPU power ascension and operation at Ginna to be acceptable in consideration of the licensee's emphasis on flow-induced vibration issues.

c. RV and Supports

Babcock & Wilcox (B&W) originally designed the Ginna RV to Westinghouse specifications and the ASME Code, Section III, 1965 Edition. In 2003, Ginna installed a replacement RVCH that B&W Canada (BWC) designed and fabricated to the requirements of technical specification BWC-TS-2915 and the ASME Code, Section III, Division 1, 1995 Edition with 1996 Addenda. The licensee additionally evaluated the RV and supports for license renewal. The staff's review is documented in Section 3.1.2 of NUREG-1786. WCAP-16411 documents a subsequent review of the RV and supports for the revised operating parameters and transients due to EPU. The WCAP documents revisions to the original B&W stress reports for RV components below the vessel flange and revisions to BWC's stress report for the replacement RVCH. The WCAP also documents an evaluation of the RV support loads. The licensee notes that BWC's stress report for the RVCH evaluated the RV head components for the operating conditions and design transients due to RSG program. The current licensing basis for the Ginna RV is documented in UFSAR Section 5.3

For the RV components below the vessel flange and for the RV supports, WCAP-16411 documents revisions to B&W's original stress reports for the revised operating temperatures, RCS transients, seismic loads, and LOCA RV/internals interface loads due to the EPU. For the replacement RVCH, the WCAP documents revisions to BWC's stress report for the revised operating temperatures, RCS transients, seismic loads, and LOCA RV/internals interface loads due to EPU.

Because the Ginna RV was originally designed to the ASME Code, Section III, 1965 Edition, the licensee adopted the following methods to evaluate the RV components below the vessel flange for EPU: (1) a "similar plant" stress report for an RV with nearly identical geometry and materials was used; (2) thermal stresses due to rapid transients were evaluated using Document PB-151987, "Tentative Structural Design Basis for Reactor Pressure Vessels," Section A.3.5, and (3) changes in pressure due to changes in design pressure transients were scaled. The licensee notes that the geometries of the "similar plant" RV and Ginna's RV are essentially identical, except for the geometries of the SI nozzle, the bottom head instrumentation tubes, and the core support guides. The licensee separately evaluated these components for EPU. For the RVCH and main closure region components, BWC's replacement head stress report was used to evaluate stresses and fatigue usage factors for EPU. The staff finds the licensee's methodology for reviewing Ginna's RV replacement head, bottom head, and supports for the effects of EPU to be acceptable.

The licensee screened the RCS transients for the EPU, the RSGs, the original design basis, and the "similar plant" transients to identify the bounding temperature and pressure transients used to evaluate the Ginna RV for EPU. The licensee notes that the calculated maximum range of primary-plus-secondary stress intensities resulting from mechanical and thermal loads for the closure head was evaluated to an acceptance criterion of 3Sm, or the alternate acceptance criteria specified in Section NB-3228.5 of the ASME Code, Section III, Division 1, 1995 Edition through 1996 Addenda. Below the vessel flange, the maximum range of primary-plus-secondary stress intensities resulting from mechanical and thermal loads was limited to 3Sm or the alternate requirements of Paragraph N-417.6(a)(2) of the ASME Code, Section III, Division 1, 1965 Edition.

Below the vessel flange, the maximum cumulative fatigue usage factor due to the normal and upset condition design transient mechanical and thermal loads was evaluated to the acceptance criterion of 1.0 specified in Paragraph –415-2 of the ASME Code, Section III, 1965 Edition. For the RV closure head components, cumulative fatigue usage factors were evaluated to the acceptance criterion of 1.0 specified in Paragraph NB-3222.4 of the ASME Code, Section III, Division 1, 1995 Edition through 1996 Addenda. The licensee also evaluated RV components for environmental fatigue usage factors due to EPU and concluded that cumulative fatigue usage factors for the RV inlet nozzle, outlet nozzle, and bottom-head-to-shell juncture remain below the ASME Code limit of 1.0.

The licensee also evaluated the impact of EPU on Ginna’s license renewal application for the RV and supports and determined that the aging evaluations the staff approved for the RV and supports in NUREG-1786 remain valid for EPU. The NRC staff concludes that the licensee evaluated Ginna’s RV replacement head, bottom head and supports to the appropriate ASME Code stress and cumulative fatigue usage factor requirements.

Table 2.2.2.3-1 of the licensing report documents the maximum ranges of stress intensities and maximum cumulative fatigue usage factors from the licensee’s evaluation of Ginna’s RV for EPU. In response to a staff RAI, the licensee provided additional information for its evaluations of the stresses and fatigue usage factors for the RV closure studs, the control rod drive mechanism (CRDM) nozzle, the inlet nozzle to shell junction, and the external support brackets. Table 2.2.2.3-1 documents a pre-EPU fatigue usage factor of 0.020 and a post-EPU fatigue usage factor of 0.979 for the external support brackets. In its response of December 19, 2005, to the staff's RAI concerning the discrepancy in the above CUF values, the licensee indicated that the CUF value for EPU condition is conservatively based on the large temperature difference between the inside and outside of the RV. This assumption was not considered in the pre-EPU original stress calculation for the external support bracket. The licensee also indicated that the majority of the calculated CUF is resulting from this additional thermal stress. Tables 2.2.2.3-3 and 2.2.2.3-4 document the licensee’s evaluation of the RV supports for faulted and normal/operating snubber reduction program and EPU loads.

Based on the licensee’s evaluations of Ginna’s RV and supports for the revised operating parameters and transients due to EPU, the licensee concludes that:

- Maximum ranges of primary-plus-secondary stress intensities and maximum cumulative fatigue usage factors satisfy ASME Code requirements.

- RV normal/operating and faulted support loads are bounded by the original design basis loads.

- The environmental effects of fatigue satisfy ASME Code requirements.

- The effects of flow-induced vibration are nominal.

- The fatigue evaluations performed for EPU demonstrate that the current design is acceptable for 60 years of plant operation.

- The aging evaluations the staff approved in NUREG-1786 for the RV and supports remain valid for EPU.

On the basis of the its review, the NRC staff concurs with the licensee's conclusions that the current design of Ginna's RV and supports for EPU remains in compliance with 10 CFR 50.55a, GDC 1, 2, 4, 14, and 15 and the ASME Code, Section III, Division 1.

d. Control Rod Drive Mechanism

The licensee's evaluation of the control rod drive mechanisms (CRDMs) for the effects of EPU is documented in Section 2.2.2.4 of the licensing report. The licensee noted that the CRDMs that Westinghouse originally supplied to Ginna were replaced during the 2003 refueling outage as part of the Ginna RV head replacement program. The licensee determined that the replacement CRDMs are equivalent to the original CRDMs. The licensee therefore used the current licensing basis for the original CRDMs to evaluate the replacement CRDMs for the effects of EPU. The current licensing basis for the original CRDMs is documented in UFSAR Sections 3.1.1.4.1, 3.7.3.1.1.3, 3.9.2.2.4.11, and 3.9.4. The licensee noted that Ginna's CRDMs were also evaluated for license renewal. The staff's review of Ginna's CRDMs for license renewal is documented in Sections 3.1 and 3.2 of NUREG-1786.

The licensee noted that Westinghouse designed and analyzed the original CRDMs in accordance with ASME Code, Section III, Division 1, 1965 Edition with Summer 1966 Addenda. Framatome ANP, Jeumont designed and analyzed the replacement CRDMs in accordance with ASME Code, Section III, Division 1, 1995 Edition with 1996 Addenda. Westinghouse's generic analyses for the original CRDMs were used to evaluate the EPU design parameters and design transients summarized in Sections 1.1 and 2.2.6 of the licensing report. Westinghouse's evaluation of the CRDMs for EPU loads is documented in CN-RCDA-04-81, "Evaluation of Model L106 CRDM and Capped Latch Housing for R.E. Ginna - Extended Power Uprate." The licensee noted that seismic loads for the CRDMs have not changed due to EPU.

The licensee used the following acceptance criteria to evaluate the CRDM reactor coolant pressure boundary for EPU:

- Stresses do not exceed ASME Code allowables

- Cumulative fatigue usage factors remain less than 1.0

With respect to the operating temperatures and pressures documented in Section 1.1 of the licensing report, the licensee noted that there is no change to the reactor coolant pressure for EPU. The hot-leg temperature defined by the vessel outlet temperature also remains less for EPU than the temperature documented in Westinghouse's generic analyses for the original CRDMs. With respect to the design transients documented in Section 2.2.6 of the licensing report, the licensee noted that the design transients for EPU are bounded by the design transients documented in Westinghouse's generic analyses for the original CRDMs. The licensee therefore concluded that CRDM stresses and fatigue usage factors continue to meet ASME allowable limits for EPU. Table 2.2.2.4-1 lists cumulative fatigue usage factors for the CRDM joints for EPU. As noted in the footnote to the table, the fatigue factors from Westinghouse's generic analyses for the original CRDMs are bounding for EPU. Since the design transients for EPU for the replacement CRDMs are bounded by the design transients documented in Westinghouse's generic analyses for the original CRDMs, the NRC staff finds that the stresses and fatigue usage factors for the replacement CRDMs continue to meet ASME allowable limits for EPU.

The licensee also evaluated the CRDMs for the effects of flow-induced vibrations (FIV) and concluded that the CRDMs are not affected by increased flow rates due to EPU.

On the basis of the staff's review of Section 2.2.2.4 of the Ginna licensing report, the staff concurs with the licensee's conclusion that the current design of the CRDMs remains in compliance with 10 CFR 50.55a, GDC 1, 2, 4, 14 and 15.

e. SGs and Supports

In 1996, the licensee replaced Ginna's SGs. B&W supplied the RSGs in accordance with B&W Specification No. TS-3270, Revision 1, "Constellation Energy R.E. Ginna Station Certified Design Specification for Replacement Steam Generator." B&W's design specification incorporates the EPU conditions documented in Table 1-1 of the licensing report. The RSGs were designed, fabricated, tested and inspected in accordance with the requirements of "Replacement Steam Generator Certified Design Specification BWNT Document 18-1224785-05," Revision 5, "Design Specification for Replacement Steam Generator for Rochester Gas and Electric Corporation Ginna Station Unit 1." B&W designed the RSG primary and secondary side pressure boundary and integral attachments in accordance with ASME Code, Section III, Division 1, Class 1, Subsection NB, NF and Appendix F, 1974 and 1986 Editions. The licensee notes that the ASME Code does not govern the design of the RSG internal components except for the U-tubes. The licensee noted that the RSGs and supports were also evaluated for license renewal. The staff's review of Ginna's RSGs is documented in Section 3.1.2 of NUREG-1786.

For EPU, the licensee evaluated the primary equipment RSG supports for the RCL piping loads due to deadweight, thermal expansion, operating basis earthquake (OBE) and safe shutdown earthquake (SSE) loads as summarized in Section 2.2.2.1 of the licensing report. The RSG support loads were evaluated to the current design basis requirements of ASME Code, Section III, Subsection NF and Appendix F, 1974 Edition. Table 2.2.2.5.1-1 lists calculated normal, upset, emergency, SSE and faulted stress margins for the RSG upper support bumpers, upper support snubbers, lower lateral supports and lower support columns. The licensee noted that calculated stresses are less than allowable stresses and are equal to or less than the current design basis stresses documented in Westinghouse Letter SE&PT-CSE-3041, "Final Report for the Robert Emmett Ginna Nuclear Generating Station Steam Generator Hydraulic Snubber Replacement Program," October 1, 1992 (Final Report attached to letter, "Evaluation of the Reactor Coolant System for the Steam Generator Hydraulic Snubber Replacement Program," September, 1992). The licensee noted that the current design basis LOCA and pipe break analyses remain valid for EPU. Since the stress margins for the RSG supports for EPU are equal to or less than the current design basis stresses, the staff agrees that the RSG supports continue to meet ASME allowable stress limits for EPU.

The licensee evaluated the structural integrity of the RSGs for the EPU parameters listed in Table 1-1 of the licensing report and the EPU design transients documented in B&W Specification No. TS-3270. The scope of the licensee's review included the RSG pressure boundary, internal and external pressure boundary attachments, and internal components. Evaluations were performed for the tubesheet, U-tubes, primary divider plate, primary head and external attachments, secondary shell and internal/external attachments, primary and secondary nozzles, primary and secondary manways, handholes, inspection ports, studs and covers on bolted openings, lower shell internals, and steam drum internals. The licensee's evaluations were performed in accordance with the current design basis requirements of ASME Code, Section III, Division 1, Class 1, Subsection NB and NF and Appendices, 1986 Edition. ASME Code, Section III, Subsections NB and NF were used as guidelines to evaluate the internal components. B&W Report BWC-143O-SR-01, Revision 1, "Constellation Energy R.E. Ginna Station Replacement Steam Generators - Qualification Report for Power Uprate Operation with Core Power of 1811 MWt," documents the licensee's RSG structural integrity evaluations for the EPU parameters documented in B&W Specification No. TS-3270. Table 2.2.2.5.2-1 lists design, normal/upset, and emergency stresses and cumulative fatigue usage factors for critical locations of primary and secondary side pressure boundary components. The table lists a number of components with fatigue factors close to the allowable fatigue factor of 1.0. Based on the licensee's RSG structural integrity evaluations, the licensee concludes that all RSG pressure boundary and internal components continue to comply with current design basis ASME Code requirements and will operate at EPU conditions for the original RSG 40-year design life except for the pressure boundary bolted opening studs. Table 2.2.2.5.2-1 of the licensing report documents design lives for the studs less than the RSG 40-year design life. In response to a staff RAI, the licensee provided additional details of the fatigue evaluations performed for the studs and noted that the stud fatigue lives could be extended by monitoring the actual number of transients that produce fatigue damage or by performing fatigue tests of the studs in accordance with ASME Code requirements. Based on the licensee's evaluations of the structural integrity of the RSGs for EPU, the NRC staff finds that RSG pressure boundary and internal components comply with current design basis ASME Code requirements for EPU. The staff notes that the documented fatigue lives of the pressure boundary bolted opening studs could be extended by monitoring the actual number of transients that produce fatigue damage in the studs or by performing fatigue tests of the studs.

The licensee performed thermal-hydraulic analyses for the RSGs due to the EPU operating conditions documented in B&W Specification No. TS-3270. RSG performance was determined for start-up and end-of-life conditions specified for tube plugging, average primary temperature, steam nozzle pressure, feedwater temperature, and primary flow rate. The EPU acceptance criteria were a moisture carry-over less than 1% of steam flow, and a two-phase stability ratio greater than 0.2. Table 2.2.2.5.3-1 of the licensing report lists the thermal-hydraulic attributes for start-up at original conditions documented in B&W Report BWI-222-7705-PR-01, Revision 1, Thermal-hydraulic Performance Report, and start-up and end-of-life at EPU conditions. The licensee concluded that all thermal-hydraulic attributes are acceptable for operation at EPU conditions. The results of the licensee's evaluations are documented in B&W Report BWC-143O-PR-01, Revision 1, "Thermal-hydraulic Performance of Replacement Steam Generators at Power Uprate Conditions." Based on the licensee's evaluations as documented in the B&W report, the NRC staff finds that RSG thermal-hydraulic attributes are acceptable for operation at EPU conditions.

The licensee evaluated the RSGs for FIV and tube wear for the EPU conditions documented in B&W Specification No. TS-3270. Evaluations of FIV and tube wear were performed for fluid-elastic instability, vortex shedding resonance (VS) and random turbulence excitation (RTE). Critical regions in the tube bundle were analyzed, taking crudded support conditions into account. The acceptance criteria for EPU were a critical velocity ratio less than 1.0 to preclude fluid-elastic instability, and accumulated tube wear over the RSG 40-year design life less than 40% of nominal tube wall thickness. Based on the evaluations documented in B&W Report BWC-143O-FIV-01, Revision 1, “Flow-induced Vibration and Wear Analysis of Replacement Steam Generators at Power Uprate Conditions,” the licensee concluded that the RSG tube bundles are adequately designed and supported for FIV and tube wear over the RSG 40-year design life at EPU conditions. Based on the licensee’s evaluations as documented in the B&W report, the NRC staff finds that the RSG tube bundles are adequately designed and supported for FIV and tube wear over the RSG 40-year design life at EPU conditions. The staff notes that the RSG tube bundles are subject to periodic surveillance in accordance with plant procedures.

With respect to the RSG moisture separators, the licensee noted that the design and testing of the RSG moisture separators is documented in B&W Report No. 77-1235965, “Replacement Steam Generator Report and Safety Evaluation for Rochester Gas and Electric Corporation / R.E. Ginna Nuclear Power Plant.” As documented in the report, the moisture separator assembly consists of a “curved-arm” primary stage and a secondary “cyclone” stage. Design maximum moisture carryover is 0.10 percent (by weight), which is less than the design value of 0.25 percent for the original SGs. As documented in the report, B&W has performed extensive evaluations of the performance of the moisture separators. At typical operating conditions, moisture carryover was shown to remain below the design value of 0.10 percent (by weight). Testing at flow rates as high as 60 percent above the flow rate showed no appreciable reduction in performance. The report also notes that the steam separators and supports are designed so that fatigue and vibration will not occur since there is no cross flow velocity and the structures are sufficiently rigid to avoid resonance due to acoustic forces. In response to a staff RAI requesting an evaluation of flow induced vibration for the moisture separators, moisture separator supports (steam dryer and dryer supports) and flow-reflector, the licensee noted that FIV was not an issue for B&W Canada (BWC) supplied SGs that use curved arm (CAP) primary steam separators. The licensee provided a table of 78 installed SGs (44 CANDU / 34 PWR) with CAP type steam separators and noted that none of the plants reported signs of fatigue or FIV in the SG internals or supports. The licensee also noted that flow reflectors are not used in BWC supplied steam generators. The licensee concluded that the RSG moisture separators are adequately designed for the effects of fatigue and FIV. Based on the licensee’s assertion that none of the 78 installed SGs (44 CANDU / 34 PWR) with CAP type steam separators supplied by BWC have exhibited signs of fatigue or FIV in the SG internals or supports, the NRC staff concurs with the licensee’s conclusion that the RSG moisture separators remain adequate for EPU.

On the basis of the staff’s review, the staff concurs with the licensee’s conclusions that the current design of the RSGs and supports and RSG moisture separators for EPU remains in compliance with 10 CFR 50.55a, GDC 1, 2, 4, 14, and 15, and the ASME Code, Section III, Division 1.

f. Reactor Coolant Pumps and Supports

The licensee evaluated RCP pressure boundary components, supports and motor for the effects of the EPU conditions. The licensee notes that the RCPs were previously evaluated for plant license renewal as documented in NUREG-1786.

The licensee evaluated the RCP pressure boundary components for the EPU operating pressure and temperature documented in Table 1.1 of the licensing report and the EPU design transients documented in Section 2.2.6 of the licensing report. The licensee noted that the current reactor coolant operating pressure remains unchanged for EPU and the maximum cold-leg temperature for EPU is less than the equipment specification operating temperature. The licensee concluded that no additional evaluation of the RCP pressure boundary components was required for the operating pressure and temperature due to EPU. With respect to the design transients summarized in Section 2.2.6 of the licensing report, the licensee evaluated the RCP pressure boundary components for the cold-leg transients due to EPU. The licensee evaluated the potential effects of the cold-leg transients on the current design basis analyses for the RCP pressure boundary components and determined that stresses and cumulative fatigue usage factors remain within ASME Code allowable limits. The licensee noted that the RCP pressure boundary components were designed, fabricated, inspected and tested in accordance with the ASME Code, although the RCP is not an ASME code pressure vessel. Table 2.2.2.6-1 of the licensing report lists stresses and usage factors for the RCP casing, main flange and main flange studs. The NRC staff finds that the RCP pressure boundary components remain acceptable for the effects of EPU since stresses and cumulative fatigue usage factors remain within ASME Code allowable limits.

The licensee evaluated the RCP supports (lateral tierods and columns) for the effects of the EPU piping loads summarized in Section 2.2.2.1 of the licensing report. The licensee noted that the current design basis seismic analysis of the RCP and supports remains unchanged. The current design basis LOCA and pipe break analyses documented in "Final Report for the Robert Emmett Ginna Nuclear Generating Station Steam Generator Hydraulic Snubber Replacement Program," October 1, 1992 and summarized in Section 2.2.2.1 of the licensing report also remain valid for EPU. The licensee evaluated the effects of the EPU piping loads on the current design basis analyses of the lateral tie-rods and columns documented in the Final Report. The licensee evaluated the RCP supports to the current design basis requirements of ASME Code, Section III, Subsection NF and Appendix F, 1974 Edition. Table 2.2.2.6-2 of the licensing report documents the normal, upset, emergency, SSE and faulted stress margins (allowable stress divided by actual stress) for the RCP lateral tie-rods and columns. Since the current design basis seismic, LOCA and pipe break analyses remain valid for EPU, the NRC staff finds that the RCP supports are acceptable for the effects of EPU.

The licensee evaluated the RCP motors for the EPU parameters summarized in Section 1.1 of the licensing report. The motors were evaluated under worst-case hot-loop and cold-loop operation horsepower loadings for continuous operation at hot-loop (100% power) and cold-loop (70 EF) conditions and for thrust bearing loading. The worst-case loads for hot-loop and cold-loop operation are less than the motor nameplate horsepower ratings. The licensee noted that testing and analysis have documented the operability of the RCP motor for the nameplate horsepower ratings and concluded that the motor loadings due to EPU are acceptable. Table 2.2.2.6-3 of the licensing report lists the brake horsepower results for the RCP motor. The licensee evaluated the motor thrust-bearing loads for EPU and confirmed that increases in thrust loads for hot-loop and cold-loop operation were not significant with respect to the normal operating thrust-bearing load documented in the RCP motor specifications. The licensee concluded that motor thrust bearing loads are acceptable for EPU. The licensee also concluded that since the motor loads for EPU are less than the motor nameplate ratings the motor temperature rise for hot and cold operating conditions will be within NEMA requirements. The licensee also evaluated the RCPs for the effects of flow induced vibration (FIV) due to EPU and concluded that the RCPs are not affected by FIV due to their heavy construction and the minor increase in flow rate for EPU. Since the worst-case loads for hot-loop and cold-loop RCP motor operation for EPU are less than the motor nameplate horsepower ratings, the NRC staff finds that the RCP motors are acceptable for the effects of EPU.

On the basis of its review regarding the design adequacy of RCP components at EPU conditions, the NRC staff concurs with the licensee's conclusion that the current design of Ginna's RCPs and supports for EPU remains in compliance with 10 CFR 50.55a, GDC 1, 2, 4, 14, and 15, and applicable ASME Code requirements.

g. Pressurizer and Supports

The licensee evaluated the pressurizer and support skirt for the effects of the EPU. The licensee noted that the Ginna pressurizer was designed, fabricated, inspected and tested to the requirements of Equipment Specification 676248 Revision 1 and the ASME Code, Section III, 1965 Edition. WCAP-12968 documented an evaluation of the pressurizer surge line in response to NRC Bulletin 88-11 and concluded that the pressurizer surge line and surge nozzle met the stress allowables and fatigue usage requirements of ASME Code, Section III, 1986 Edition. Generic Topical Report WCAP-14754-A documented pressurizer aging management issues. The WCAP concluded that fatigue was the only time-limited aging analysis for pressurizers. WCAP-12928 addressed the Ginna pressurizer's potential for environmentally assisted fatigue during the period of extended operation. The licensee evaluated Ginna's pressurizer for plant license renewal as described in NUREG-1786. Section 4.3.2.7 of the NUREG documented the staff's acceptance of the licensee's fatigue evaluations of sensitive pressurizer components and the licensee's implementation of a program to monitor the number of thermal transients causing fatigue.

To evaluate the Ginna pressurizer and support skirt for EPU, the licensee performed evaluations of the operating parameters summarized in Section 1.1 and the design transients summarized in Section 2.2.6 of the licensing report with respect to the operating and transient conditions evaluated in Equipment Specification 676248. The licensee noted that there are no other changes to the pressure or thermal-hydraulic design parameters due to EPU that would affect the pressurizer or its supports. No new design transients were identified for EPU. The licensee evaluated the operating parameters and design transients for EPU with respect to the operating and transient conditions addressed in Equipment Specification 676248 for the following initial acceptance criteria:

- Hot and cold temperatures remained within the ranges of the operating temperatures that had previously been evaluated.

- The severity and number of design transients were less than or equal to previously evaluated design transients.

- No new design transients were identified.

- Design loads less than or equal to previously evaluated design loads with no changes to load locations or number of occurrences.

The licensee concluded that the revised operating parameters and design transients for EPU did not impact the existing pressurizer stress or fatigue analyses or the surge line stratification analysis performed for the surge nozzle. The conclusions in NUREG-1786 on fatigue remain valid for EPU because the heatup and cooldown transients and pressurizer surge transients remain unchanged and the design transients evaluated in Equipment Specification 676248 bound the remaining design transients. Since the operating parameters and design transients for EPU do not impact the existing pressurizer stress or fatigue analyses or the surge line stratification analysis performed for the surge nozzle, the NRC staff finds that the pressurizer remains acceptable for the effects of EPU.

The NRC staff reviewed the pressurizer support skirt as part of the SEP program and concluded that the Ginna pressurizer was adequately supported for the safe shutdown earthquake (SSE). The licensee noted that the seismic analyses of record are not affected by EPU conditions. The licensee also evaluated the pressurizer for the effects of FIV due to EPU and concluded that the pressurizer is not affected by FIV due to relatively low fluid flow rates. The NRC staff finds that the seismic analysis of record for the pressurizer is not affected by EPU conditions and that the pressurizer support skirt remains adequate for the effects of EPU.

On the basis of its review that the current design basis is bounding for the EPU conditions, the NRC staff concurs with the licensee's conclusion that the current design of Ginna pressurizer and supports for EPU remains in compliance with 10 CFR 50.55a, and GDC 1, 2, 4, 14, and 15, and applicable ASME Code requirements.

Conclusion

The NRC staff has reviewed the licensee's evaluations related to the structural integrity of pressure-retaining components and their supports. As discussed above, the NRC staff concludes that the licensee has adequately addressed the effects of the proposed EPU on these components and their supports. Based on the above, the NRC staff further concludes that the licensee has demonstrated that pressure-retaining components and their supports will continue to meet the requirements of 10 CFR 50.55a and GDC 1, 2, 4, 14, and 15 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the structural integrity of the pressure-retaining components and their supports.

2.2.3 Reactor Pressure Vessel Internals and Core Supports

Regulatory Evaluation

Reactor pressure vessel internals consist of all the structural and mechanical elements inside the RV, including core support structures. The NRC staff reviewed the effects of the proposed EPU on the design input parameters and the design-basis loads and load combinations for the reactor internals for normal operation, upset, emergency, and faulted conditions. These include pressure differences and thermal effects for normal operation, transient pressure loads associated with loss-of-coolant accidents (LOCAs), and the identification of design transient occurrences. The NRC staff's review covered (1) the analyses of flow-induced vibration for safety-related and non-safety-related reactor internal components and (2) the analytical methodologies, assumptions, ASME Code editions, and computer programs used for these analyses. The NRC staff's review also included a comparison of the resulting stresses and CUFs against the corresponding Code-allowable limits. The NRC's acceptance criteria are based on (1) 10 CFR 50.55a and GDC 1, insofar as they require that SSCs important to safety be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC 2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions; (3) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; and (4) GDC 10, insofar as it requires that the reactor core be designed with appropriate margin to assure that specified acceptable fuel design limits (SAFDLs) are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences. Specific review criteria are contained in SRP Sections 3.9.1, 3.9.2, 3.9.3, and 3.9.5, and other guidance provided in Matrix 2 of RS-001.

Technical Evaluation

The licensee's evaluations of Ginna's RV internal components and core supports for the effects of EPU are summarized in Section 2.2.3 of the licensing report. The licensee notes that the current licensing basis analyses for Ginna's RV internal components and core supports are summarized in Ginna UFSAR Sections 3.9.2.3.6, 3.9.2.5.1, 3.9.5, and 4.2.1.3.4.1. The staff's evaluations of the Ginna RV internal components and core supports for plant license renewal are documented in Sections 3.0 and 3.1 of NUREG-1786. The aging evaluations the staff approved for the Ginna RV internal components and core supports are documented in Section 4.3 of NUREG-1786.

For EPU, the licensee evaluated Ginna's RV internal components and core supports for the design parameters summarized in Section 1.1 of the licensing report and the design transients discussed in Section 2.2.6 of the licensing report. The licensee evaluated the RV internal components and core supports for the normal, upset, emergency and faulted (LOCA/seismic) load combinations. The licensee's evaluations assumed a full core of Westinghouse Vantage + fuel without intermediate flow mixing (IFM) grids with the thimble plugging devices removed.

The licensee used the following acceptance criteria for these evaluations:

- Design core bypass flow limit with thimble plugging devices removed is 6.5% of the total vessel flow rate.

- Rod cluster control assembly (RCCA) drop time TS of 1.8 seconds to be maintained.

- Core support component stresses meet allowable stress limits and cumulative fatigue usage factors remain less than 1.0.

The licensee performed thermal hydraulic evaluations of the reactor coolant flow due to EPU. The licensee's evaluation of core bypass flow due to EPU determined that the design core bypass flow value of 6.5% with thimble plugging devices removed remains acceptable. The licensee's evaluation of the hydraulic lift forces on the reactor internal components for EPU determined that the reactor internals will remain seated and stable. The licensee's evaluation of the RCCAs due to EPU determined that the maximum estimated RCCA drop time to the top of dashpot remains less than the current TS limit of 1.8 seconds.

The licensee performed mechanical system evaluations to evaluate the current licensing basis LOCA and seismic analyses for EPU. Due to the LBB methodology summarized in Section 2.1.6 of the licensing report, the largest branch lines considered were the 3-inch pressurizer spray line connected to the cold leg and the 4-inch upper plenum injection (UPI) line. Although EPU does not impact the seismic response of the reactor internals, the licensee performed a nonlinear time history seismic analysis of the RV system due to changes in the fuel assembly design.

The most critical internal components evaluated for EPU were:

- Upper support plate/deep beam structure
- Upper core plate
- Upper core plate fuel pins
- Upper support column
- Lower support plate
- Lower core plate
- Lower support column
- Core barrel
- Thermal shield and flexures
- Radial keys and clevis insert assembly
- Baffle-former assembly

The licensee's evaluation of the above internal components for EPU determined that stresses are within allowable and fatigue usage factors are less than 1.0. Table 2.2.3-3 summarizes the calculated and allowable stresses and fatigue usage factors for the above-listed internal components except for the baffle-former assembly. It is noted that several of the internal components listed in Table 2.2.3-3 have calculated stresses that exceed the 3Sm limit. As permitted, the licensee reevaluated these internal components to the requirements of ASME Code, Section III, Subsection NB 3228.5. In response to a staff RAI, the licensee summarized calculated stresses and fatigue usage factors for the core barrel assembly upper girth welds, lower girth welds and core barrel outlet nozzle; the thermal shield flexures, lower support plate, lower radial restraints and lower core plate. With respect to the baffle-former assembly, the licensee evaluated the baffle-former bolts for pressure, seismic, LOCA, preload and thermal loads due to EPU. The licensee noted that the largest loads on the baffle-former bolts are due to the temperature difference between the baffle and barrel. The licensee noted that the fatigue lives of the baffle-former bolts are based on a fatigue test. The licensee concluded that the fatigue lives of the baffle-former bolts remain adequate for the plant loading and unloading design transient due to EPU. The licensee noted that Table 3.1-1 of NUREG-1786 documents aging degradation issues for the baffle-former bolts that are being managed by the licensee's fatigue monitoring program. The NRC staff concurs with the licensee's conclusions that the RV internal components are acceptable for EPU since the maximum stress intensity ranges and cumulative fatigue usage factors for the RV internal components continue to meet ASME Code limits.

The licensee also evaluated the RV internal components for FIV due to EPU and concluded that fatigue usage factors for the internal components are nominal due to the high-cycle endurance limit of the component material. Tables 2.2.3-1 and 2.2.3-2 of the licensing report summarize the results of the licensee's FIV evaluations for EPU.

On the basis of the its review, the staff concurs with the licensee's conclusion that the current design of Ginna's RV internal components and core supports remains in compliance with 10 CFR 50.55a, GDC 1, GDC 2, GDC 4, and GDC 10 for EPU.

Conclusion

The NRC staff has reviewed the licensee's evaluations related to the structural integrity of reactor internals and core supports and concludes that the licensee has adequately addressed the effects of the proposed EPU on the reactor internals and core supports. The NRC staff further concludes that the licensee has demonstrated that the reactor internals and core supports will continue to meet the requirements of 10 CFR 50.55a, GDC 1, GDC 2, GDC 4, and GDC 10 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the design of the reactor internal and core supports.

2.2.4 Safety-Related Valves and Pumps

Regulatory Evaluation

The NRC staff's review included certain safety-related pumps and valves typically designated as Class 1, 2, or 3 under Section III of the ASME Code and within the scope of Section XI of the ASME Code and the ASME *Code for Operation and Maintenance of Nuclear Power Plants* (OM Code), as applicable. The NRC staff's review focused on the effects of the proposed EPU on the required functional performance of the valves and pumps. The review covered any impacts that the proposed EPU may have on the licensee's motor-operated valve (MOV) programs related to Generic Letter (GL) 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," and GL 96-05, "Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves." The review addressed the performance of power-operated valves as discussed in GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves." The NRC staff also evaluated the licensee's consideration of lessons learned from the MOV program and the application of those lessons learned to other safety-related power-operated valves. The NRC's acceptance criteria are based on (1) GDC 1, insofar as it requires those systems and components which are essential to the prevention of accidents which could affect the public health and safety or to mitigation of their consequences be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC 38, 46, 47, 48, 59, 60, 61, 63, 64, and 65 insofar as they require that the ECCS, the containment heat removal system, the containment atmospheric cleanup systems, and the cooling water system, respectively, be designed to permit appropriate periodic testing to ensure the leak-tight integrity and performance of their active components; (3) GDC 57, insofar as it requires that piping systems penetrating containment be designed with the capability to periodically test the operability of the isolation valves to determine if valve leakage is within acceptable limits; and (4) 10 CFR 50.55a(f), insofar as it requires that pumps and valves subject to that section must meet the inservice testing program requirements identified in that section. Specific review criteria are contained in SRP Sections 3.9.3 and 3.9.6.

Technical Evaluation

The NRC staff conducted a technical evaluation of the licensee's EPU request submitted on July 7, 2005, as supplemented by letters dated August 15, and September 30, 2005. The staff provided requests for additional information (RAIs) to the licensee with regard to the performance of safety-related pumps and valves under EPU conditions, as well as other areas of review. The licensee submitted responses to the NRC staff RAIs in letters dated December 19, 2005, and January 25, 2006. The staff reviewed the RAI responses submitted by the licensee and discussed that information with the licensee by telephone.

In its EPU license amendment request and RAI responses, the licensee discussed the potential impact of EPU conditions on safety-related pumps and valves at Ginna. In particular, the licensee described the impact of EPU conditions on safety-related pumps and valves in the NSSS (such as RCS, chemical & volume control system, SI system, RHR system, and containment spray (CS) system) and additional Balance of Plant (BOP) systems. Negligible impact on system operating pressures, flow rates, and pump head performance was found for NSSS systems under normal operating conditions. Further, accident and transient analyses found the safety-related pumps and valves in the NSSS systems to be capable of continuing to meet their performance requirements under EPU conditions. The staff also reviewed the licensee's assessment of the impact of EPU conditions on safety-related pumps and valves in BOP systems (including main steam system, main feedwater system, AFW system, service water system, component cooling water system, spent fuel pool cooling and cleanup system, and containment isolation system). With the exception of the main feedwater system (discussed below), the licensee did not identify any significant modifications or adjustment to the safety-related pumps or valves in the BOP systems. The licensee's assessment of individual safety-related valves addressed several plant programs including those implemented in response to GL 89-10, GL 95-07, and GL 96-05. The NRC staff conducted several inspections of the safety-related MOV program at Ginna in response to GL 89-10, and closed its review based on those inspections. As described in an SE dated July 19, 1999, the NRC staff reviewed and accepted the licensee 's actions at Ginna in response to GL 95-07. In an SE dated December 27, 1999, the NRC staff described its acceptance review of the MOV program being implemented at Ginna in response to GL 96-05.

With respect to the main feedwater system, the licensee will replace the main feedwater regulating valves (MFRVs) to provide the necessary flow and pressure at EPU conditions. The licensee is also implementing a trim modification to the main feedwater bypass valves (MFBPVs) to provide for improved control under EPU conditions. In addition, the licensee submitted an application on April 29, 2005 (Reference 5), with a supplement on July 1, 2005, to amend the TSs to allow the use of the MFIVs in lieu of the main feedwater pump discharge valves, to provide isolation of the SGs in the event of a steam line break. The NRC staff review of the modification of the MFIVs is described in an SE dated March 16, 2006.

The NRC staff reviewed the licensee's assessment of the performance of safety-related pumps and valves at Ginna under EPU conditions, including the specific examples discussed in the EPU request and RAI responses. From its review, the staff determined that the licensee' s assessment of safety-related pumps and valves at Ginna for EPU conditions was appropriate in light of operating experience and previous regulatory guidance.

Conclusion

The NRC staff has reviewed the licensee's assessments related to the functional performance of safety-related valves and pumps at Ginna under EPU conditions. Based on its review, the staff determined that the licensee has adequately addressed the effects of the proposed EPU on safety-related pumps and valves. The staff concludes that the licensee has demonstrated that safety-related valves and pumps will continue to meet the requirements of GDC 1, 38, 46, 47, 48, 57, 59, 60, 61, 63, 64, and 65, and 10 CFR 50.55a(f) following implementation of the proposed EPU.

2.2.5 Seismic and Dynamic Qualification of Mechanical and Electrical Equipment

Regulatory Evaluation

Mechanical and electrical equipment covered by this section includes equipment associated with systems that are essential to emergency reactor shutdown, containment isolation, reactor core cooling, and containment and reactor heat removal. Equipment associated with systems essential to preventing significant releases of radioactive materials to the environment are also covered by this section. The NRC staff's review focused on the effects of the proposed EPU on the qualification of the equipment to withstand seismic events and the dynamic effects associated with pipe-whip and jet impingement forces. The primary input motions due to the safe shutdown earthquake (SSE) are not affected by an EPU. The NRC's acceptance criteria are based on (1) GDC 1, insofar as it requires that SSCs important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC 30, insofar as it requires that components that are part of the RCPB be designed, fabricated, erected, and tested to the highest quality standards practical; (3) GDC 2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions; (4) 10 CFR Part 100, Appendix A, which sets forth the principal seismic and geologic considerations for the evaluation of the suitability of plant design bases established in consideration of the seismic and geologic characteristics of the plant site; (5) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (6) GDC 14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture; and (7) 10 CFR Part 50, Appendix B, which sets quality assurance requirements for safety-related equipment. Specific review criteria are contained in SRP Section 3.10.

Technical Evaluation

Due to the application of LBB, breaks are not postulated for the RCL main loop piping, the pressurizer surge line, and the accumulator and residual heat removal lines.

For EPU, the loop LOCA hydraulic forcing function forces and associated loop LOCA RPV motions from the smaller branch line breaks are used; i.e., the 3-inch pressurizer spray line on the cold leg, the 2-inch safety injection line on the hot leg, and the 4-inch upper plenum injection line connections to the vessel.

The licensee's evaluation of the dynamic effects of pipe-whip and jet impingement for EPU is documented in Sections 2.2.1 and 2.5.1.3 of the Ginna licensing report. Section 2.5.1.2 of the licensing report documents the licensee's evaluation of the dynamic effects of internally and externally generated missiles for EPU. Based on these evaluations, the licensee concludes that EPU will have no adverse impact on essential equipment as a result of pipe whip, jet impingement, and internal and external missiles. In addition, the design basis seismic analysis of safety-related equipment is not affected by the EPU, so that the seismic qualification of essential equipment remains unchanged. The NRC staff's review of the licensee's evaluations of the design basis for the postulated rupture of piping inside and outside containment for EPU is documented in Section 2.2.1 of this report. The staff concurs with the licensee's conclusion that the seismic qualification of essential equipment remains unchanged for the EPU.

Conclusion

The NRC staff has reviewed the licensee's evaluations of the effects of the proposed EPU on the qualification of mechanical and electrical equipment and concludes that the licensee has (1) adequately addressed the effects of the proposed EPU on this equipment and (2) demonstrated that the equipment will continue to meet the requirements of GDCs 1, 2, 4, 14, and 30; 10 CFR Part 100, Appendix A; and 10 CFR Part 50, Appendix B, following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the qualification of the mechanical and electrical equipment.

2.3 Electrical Engineering

2.3.1 Environmental Qualification of Electrical Equipment

Regulatory Evaluation

The term "environmental qualification" applies to equipment that must remain functional during and following design basis events. The NRC staff's review covers the environmental conditions which could affect the design and safety functions of electrical equipment including instrumentation and control. The staff's review verifies compliance with the acceptance criteria thus ensuring that the equipment continues to be capable of performing its design safety functions under all normal environmental conditions, anticipated operational occurrences, and accident and post accident environmental conditions. Acceptance criteria are based on 10 CFR 50.49, as it relates to specific requirements regarding the qualification of electrical equipment important to safety that is located in a harsh environment. Specific review criteria are contained in SRP Section 3.11, "Environmental Qualification of Mechanical And Electrical Equipment."

Technical Evaluation

The environmental qualification of electrical equipment is performed for the components identified in the Environmental Qualification Master Equipment List. The equipment qualification parameters were compared to the EPU parameter values to demonstrate the continued qualification of the equipment under proposed EPU conditions. The environmental parameters for both normal operation (including anticipated operational occurrences) and design-basis accidents (DBAs) are temperature, pressure, radiation dose, and humidity. The transient temperatures associated with anticipated operational occurrences, such as turbine trips or the loss of a ventilation system, could increase slightly as a result of EPU but will have no impact on the equipment qualification. The peak temperature values for the DBAs bound the temperature transients of the anticipated operational occurrences, such as turbine trips or the loss of a ventilation system, could increase slightly as a result of EPU but will have no impact on the equipment qualification. The peak temperature values for the design basis accidents bound the temperature transients of the anticipated operational occurrences.

Design basis accident conditions for equipment qualification inside the containment are the result of the loss of coolant accident. The loss-of-coolant temperature and pressure vs. time profiles for EPU conditions were compared to the temperature and pressure profiles that are the pre-EPU basis for equipment qualification. The results showed that the EPU temperature and pressure conditions are bounded. The normal operating temperature, pressure, and humidity for equipment qualified life inside containment do not change for EPU operation. The accident temperature, pressure, and humidity inside the containment are bounded by the pre-EPU accident profiles used for the equipment qualification. The equipment is therefore qualified for the EPU accident conditions.

The high energy line breaks (HELBs), which are the bases for equipment qualification outside containment, do not change as a result of EPU operation. All equipment outside containment is qualified for the EPU conditions.

The design basis radiation environments used for equipment qualification are based on the loss of coolant accident. The increased normal operation and accident radiation environments due to the EPU were compared to the environmental qualification data to demonstrate continued qualification of electrical equipment important to safety.

Conclusion

The NRC staff has reviewed the effects of the proposed power uprate on the environmental qualification of the electrical equipment and concludes that the electrical equipment continues to meet the relevant requirements of 10 CFR 50.49. Therefore, the staff finds the proposed power uprate acceptable with respect to environmental qualification of electrical equipment.

2.3.2 Offsite Power System

Regulatory Evaluation

The offsite power system includes two or more physically independent circuits capable of operating independently of the onsite standby power sources. The staff's review covers the information, analyses and documents for the offsite power system and the stability studies for the electrical transmission grid. The focus of the review relates to the basic requirement that the loss of the nuclear unit, the largest operating unit on the grid or the loss of the most critical transmission line will not result in the loss of offsite power to the plant. Branch Technical Position (BTP) Instrumentation and Control System Branch (ICSB) 11, "Stability of Offsite Power Systems," and Power System Branch (PSB) -1, "Adequacy of Station Electric Distribution System Voltages," outline an acceptable approach to review offsite power systems issues. Acceptance criteria are based on GDC 17, "Electric Power Systems." Specific review criteria are contained in SRP Sections 8.1, "Electric Power-Introduction," and 8.2, "Offsite Power System," Appendix 8-A to 8.2 and BTPs PSB -1 and ICSB-11.

Technical Evaluation

1. Grid Stability

The licensee performed a System Reliability Impact Study to evaluate the impact of the EPU on the reliability of the local 115 kV and New York Independent System Operator (NYISO) bulk power systems. The study was performed in accordance with the NYISO requirements, including the New York State Reliability Council's Reliability Rules for Planning and Operating the New York Bulk Power System, the Northeast Power Coordinating Council's Basic Criteria for Design and Operation of Interconnected Power Systems, and the North American Electric Reliability Council's Planning Standards. The licensee has an agreement with Rochester Gas & Electric for the station to provide grid support up to +/- 100 MVAR (lagging/leading) at the grid connections. EPU modifications will result in the main generator name plate rating increasing to 667 MVA at 0.92 power factor lagging (+261 MVAR) and 0.975 power factor leading (-140 MVAR). After accounting for station loads, transformer losses, and voltage regulator setpoints the net MVAR capability in the grid is approximately +192 MVAR lagging and -152 MVAR leading. Re-rating of the main generator and the changes being implemented in the main generator voltage regulator will actually increase the capability of Ginna to supply MVAR to the grid.

Thermal, voltage, stability, and short-circuit results, with and without the Ginna at EPU conditions, were compared to determine any detrimental impact of the proposed EPU and were found to be acceptable. Thermal, voltage, and stability analyses were performed on the summer cases and thermal analysis was performed on the winter cases. Pre-contingency and contingencies were evaluated with load flow analysis for each seasonal condition. This analysis involved an extensive examination of contingencies of local and cross-state transmission facilities located around the Ginna plant area.

Several analyses were performed in the study, including thermal, voltage, stability and short circuit cases. Extreme contingencies (i.e. loss of entire generation units) were also evaluated and found to be acceptable. The licensee concluded that there was essentially no voltage variation between the base case and EPU case.

The NRC staff finds that the results of the grid stability studies performed by the licencee indicate that grid remains stable for the EPU conditions. Therefore, the power uprate will not adversely impact the availability of the offsite power source for Ginna and the plant continues to be in conformance with GDC 17 under EPU conditions.

2. Main Generator

The main generator existing rating is 608.4 MVA at a 0.85 power factor. In order to support unit operation at EPU conditions, a generator uprate study was performed and as a result, the generator rating will be revised to 667 MVA at a 0.92 power factor lagging. The licensee stated that the increased rating will be accomplished by modifying the hydrogen cooling system to improve generator cooling. The increased generator rating and the changes being implemented in the main generator voltage regulator is adequate to support unit operation at EPU, including machine -140 MVAR leading and 261 MVAR lagging reactive power requirements.

The NRC staff concludes that the main generator operation will be acceptable after modifications to the generator cooling system under EPU conditions.

3. Iso-Phase Bus Duct

The existing main isolated phase bus duct main bus continuous current design rating is 20 kA, forced cooled. As a result of the EPU evaluations, the main isolated phase bus duct main bus will be upgraded to 21.35 kA, which bounds unit operation at worst-case EPU loading conditions.

The licensee states that the only change needed to accomplish the upgrade to 21.35 kA is to increase the main bus forced cooling, which will be accomplished before EPU. In addition, the evaluation of the isolated phase bus tap bus confirms that its continuous current rating envelops the anticipated worst-case bus loading at EPU conditions. Also, the evaluation indicates that the isolated phase bus main and tap bus short circuit design ratings envelop the available fault current levels at EPU conditions. Based on the above, the NRC staff concludes that the design of the iso-phase bus will be acceptable after modifications under EPU conditions.

4. Generator Step-up Transformer

The licensee evaluated the generator step up transformer equipment for the EPU conditions. The evaluation confirms that the existing generator step up transformer design rating at 65 EC is inadequate to support unit operation at EPU conditions. The modifications are required to upgrade the transformer rating from 616 MVA to 680 MVA at 65 EC. These modifications include replacement of all three high voltage bushings and replacement of all four of the transformer coolers and cooler oil pumps, and the addition of a fifth cooler/pump unit. The modifications will be implemented prior to EPU.

The NRC staff concludes that after replacing the generator step up transformer high voltage bushings and the modifications to the transformer cooling system, the generator step up transformer will be able to carry the main generator loading of 667 MVA and is, therefore, acceptable under EPU conditions.

5. Station Auxiliary Transformers

The licensee's evaluation confirmed that the station auxiliary transformer 12A and 12B design rating of 41.8 MVA at 65 EC is adequate to support unit operation at EPU conditions.

The NRC staff reviewed the Tables 2.3.2-2 and 2.3.2-3 in the licensing report and concluded that, since the total calculated loading on the station auxiliary transformers 12A and 12B are within their ratings of 41.8 MVA at 65 EC, they are acceptable under EPU conditions.

6. Non-Class 1E Loads

The licensee stated that the condensate and feedwater flow rates will increase proportional to the uprate power increase. This will result in higher capacity condensate booster pump motors, and main feedwater pumps motors and feeder cables to deliver the needed flow to the SGs. These pump motors are being replaced and revised protective relay settings will be implemented prior to EPU. The NRC staff concurs with the licensee that the condensate pump motor and protective relay settings, feedwater pump motors and their feeder cables and the protective relay settings need to be replaced prior to EPU.

Conclusion

Based on its review, the NRC staff finds that the offsite power system at Ginna will continue to meet the requirements of GDC 17 following implementation of the proposed EPU. In this regard, the staff considered the effect of modifications to the generator, isolated phase bus duct, and generator step-up transformer cooling systems, and increasing the sizes of condensate and main feedwater pump motors. Also, the impact of the proposed EPU does not degrade grid stability. Grid stability studies have demonstrated that for EPU the transmission grid remains stable. Therefore, the proposed EPU is acceptable with respect to the offsite power system after completion of the above modifications.

2.3.3 Emergency Diesel Generators

Regulatory Evaluation

The ac onsite power system includes those standby power sources, distribution systems, and auxiliary supporting systems provided to supply power to the safety-related equipment. The NRC staff's review covers the descriptive information, analyses, and referenced documents for the ac onsite power system. Acceptance criteria are based on GDC 17 as it relates to the capability of the ac onsite power system to perform its intended functions during all plant operating and accident conditions. Specific review criteria are contained in SRP Sections 8.1 and 8.3.1.

Technical Evaluation

The NRC staff reviewed the licensee's submittal to determine whether the emergency diesel generators (EDGs) would remain capable of performing the intended design function at EPU conditions. The licensee stated that its review of the loads for operation at the EPU conditions indicated that there are no load additions or modifications required to the existing 1950 kW (continuous rating) EDGs. Therefore, there is no impact to the existing EDG loading analysis and their acceptability for EPU operation. As such, no EDG modifications are required to support EPU operation.

Conclusion

The NRC staff finds that the capacity of each EDG is adequate to support the operation under EPU conditions and no EDG modifications are required to support EPU operation because there are no changes to the safety-related loads. Therefore, the NRC staff finds the proposed power uprate acceptable with respect to the onsite ac power system.

2.3.4 Direct Current (DC) Distribution System

Regulatory Evaluation

The dc power systems include those dc power sources and their distribution systems and auxiliary supporting systems provided to supply motive or control power to safety-related equipment. The NRC staff's review covers the information, analyses, and referenced documents for the dc onsite power system. Acceptance criteria are based on GDC 17 and 10 CFR 50.63, as they relate to the capability of the dc onsite electrical power to facilitate the functioning of structures, systems, and components important to safety. Specific review criteria are contained in SRP Sections 8.1 and 8.3.2

Technical Evaluation

The NRC staff reviewed the application to determine whether the 125 volt dc system and its components would remain capable of performing their intended design function at EPU conditions. The licensee stated that plant modifications associated with the EPU will result in a slight increase in dc system loading. This increase is 0.376 amperes for Train A and 0.329 amperes for Train B. These increases are insignificant because the calculated load amperes used in the licensee's evaluation conservatively exceed the measured amperes by approximately 23% for battery "A" and approximately 30% for battery "B." The licensee also stated that the new loads will be supplied from fused circuits, therefore, they will not introduce any new failure modes or effects into the dc system.

Conclusion

The NRC staff finds that the additional loads will not impact the capability and capacity of the 125 Vdc system and separate and independent station battery systems will be maintained to supply power to all safety loads in accordance with Ginna current licensing basis with respect to the requirements of GDC 17, therefore the proposed EPU is acceptable.

2.3.5 Station Blackout

Regulatory Evaluation

Station blackout (SBO) refers to the complete loss of ac electric power to the essential and nonessential switchgear buses in a nuclear power plant, and involves the loss of offsite power concurrent with turbine trip and failure of the onsite emergency ac power system. SBO does not include the loss of available ac power to buses fed by station batteries through inverters or the loss of power from "alternate ac sources" (AAC). The NRC staff's review focused on the impact of the proposed power uprate on the plant's ability to cope with and recover from an SBO event as based on 10 CFR 50.63. Specific review criteria are contained in SRP Section 8.1 and Appendix B to SRP 8.2.

Technical Evaluation

Ginna was evaluated against the requirements of the SBO Rule, 10 CFR 50.63, using the guidance from NUMARC 87-00 and RG 1.155. Using the guidance of NUMARC 87-00, the Ginna SBO scoping duration of 4 hours has not changed under EPU conditions. The SBO rule requires that the following issues be addressed:

1. Condensate Inventory for Decay Heat Removal

The required condensate inventory, at the current licensed power level of 1520 MWt, for decay heat removal and plant cooldown was determined to be 48,239 gallons. Once this required inventory exceeds the minimum usable volume of water in the condensate storage tanks as specified in the TSs, a backup source of condensate is required. Licensee's design analysis showed that the fire water system is able to supply the condensate storage tanks at a flow rate, which will satisfy the condensate storage volume requirement for 4-hour SBO coping period.

2. Class 1E Battery Capacity

Each of the two station batteries is capable of carrying its expected shutdown loads following a plant trip and a loss of all ac power for a period of 4 hours without battery terminal voltage falling below 108.6 V. The licensee's design analysis demonstrates that the two 60-cell lead-acid, 1495 amp-hour, vital batteries "A" and "B" have sufficient capacity for the 4-hour SBO coping duration.

3. Compressed Air

During an SBO, station air can be supplied by a portable diesel-driven air compressor. However, in the event of loss of all plant air, the air-operated valves required for decay heat removal during an SBO have sufficient backup supplies.

4. Effects of Loss of Ventilation

The dominant areas of concern regarding loss of ventilation are the TDAFW pump area and the atmospheric relief valve area. The licensee stated that since the main steam temperature used in the analyses for current plant conditions envelopes the main steam temperature at EPU conditions, the EPU does not affect the results of the current plant analyses for maximum temperatures in the TDAFW pump area and the atmospheric relief valve area.

Conclusion

The NRC staff has reviewed the application regarding the effect of the proposed EPU on the plant's ability to cope with and recover from an SBO event for the period of time established in the current licensing basis. The staff concluded that the licensee has adequately evaluated the effects of the proposed power uprate on SBO and demonstrated that the plant will continue to meet the requirements of 10 CFR 50.63 following the implementation of the proposed power uprate because the plant systems have adequate capacity and capability to meet the specified coping duration. Therefore, the staff finds the proposed power uprate acceptable under 10 CFR 50.63.

2.4 Instrumentation and Controls

Regulatory Evaluation

Instrumentation and control systems are provided (1) to control plant processes having a significant impact on plant safety, (2) to initiate the reactivity control system (including control rods), (3) to initiate the engineered safety features (ESF) systems and essential auxiliary supporting systems, and (4) for use to achieve and maintain a safe shutdown condition of the plant. Diverse instrumentation and control systems and equipment are provided for the express purpose of protecting against potential common-mode failures of instrumentation and control protection systems. The NRC staff conducted a review of the reactor trip system, engineered safety feature actuation system (ESFAS), safe shutdown systems, control systems, and diverse instrumentation and control systems for the proposed EPU to ensure that the systems and any changes necessary for the proposed EPU are adequately designed such that the systems continue to meet their safety functions. The NRC staff's review was also conducted to ensure that failures of the systems do not affect safety functions. The NRC's acceptance criteria related to the quality of design of protection and control systems are based on 10 CFR 50.55a(a)(1), 10 CFR 50.55a(h), and the GDC described in the Ginna UFSAR - GDC 1, 2, 4, 13, 19, 20, 21, 22, 23, 24, 25, and 29. The current licensing basis and performance criteria are described in Ginna UFSAR Sections 7.1.2, 7.2, 7.3, 7.4, 7.5, 7.6, and 7.7. Specific review criteria are contained in SRP Sections 7.0, 7.2, 7.3, 7.4, 7.7, and 7.8.

Technical Evaluation

a. Suitability of Existing Instruments

For the proposed power uprate, the licensee evaluated each existing instrument of the affected NSSS systems and balance-of-plant (BOP) systems to determine its suitability for the revised operating range of the affected process parameters. Where operation at the EPU condition impacted safety analysis limits, the licensee verified that the acceptable safety margin continued to exist under all conditions of the power uprate. Where necessary, the licensee revised the setpoint and uncertainty calculations for the affected instruments. Apart from a few devices that needed change, the licensee's evaluations found most of the existing instrumentation acceptable for proposed power uprate operation. The licensee's evaluation resulted in the following changes at Ginna:

1. Reactor Protection System (RPS) Instrumentation:

a. Nuclear Instrumentation:

Power range monitors and Intermediate monitors will be recalibrated to account for the change in percent power level and the 100% power flux level. Once calibrated , the power range reactor trips, rod stops and input to permissives P-1, P-7, P-8, P-9, and P-10 will function at the appropriate relative power setpoint.

The analytical limit (AL) for the power range high power trip will be reduced from the current 118% to 115% value. This does not affect the current field setpoint of 108% for high power trip as it has adequate margin.

b. RCS Temperature Instrumentation

The T_{cold}, T_{hot}, T_{avg}, and ÎT instruments including indications will be recalibrated for a range as follows:

C T_{cold} 510 EF - 590 EF

C T_{hot} 540 EF - 650 EF

C T_{avg} 540 EF - 620 EF

C ÎT 0 EF - $80 EF

In addition to this a 4.5 second filter will be added to improve the margin to trip for the overtemperature ªT and overpower ªT trips and to add stability to the rod control system.

c. Overtemperature ªT (OTªT) trip

The AL for OTªT will be changed from 1.32073 to 1.30 and the value of Constants K1, K2, and K3 will be changed from 1.20 to 1.19, 0.0009/psi to 0.00093/psi, and 0.0209/EF to 0.0185/EF, respectively. Also, the current f(ªI) control function of the OTªT trip setpoint only responds to a positive axial offset, therefore, an additional module will be added to the system to account for a negative axial offset. The f(ªI) function will be calibrated for EPU conditions in accordance with the value listed in the cycle specific core operating limits report (COLR).

d. Overpower ªT (OPªT) trip

The AL for OPªT will be changed from 1.14877 to 1.15 and the value of the Constants K5 and K6, and time constant t3 will be changed from 0.0011/EF to 0.0014/EF, 0.0262/EF to 0.0/EF, and 10 seconds to 0 seconds, respectively. Also, the f(ªI) function is not necessary for OPªT trip circuit, therefore, this function is being disabled for EPU operation.

e. OTªT and OPªT rod stops

The setpoint for the P-1 permissive is being redefined from a specific temperature value (1.71 EF) to a value 3% below the full power ªT. This is not a technical change as 1.71 EF corresponds to a value 3% below the pre-uprate full power ªT. At EPU conditions, the 3% below full power ªT will correspond to a rod stop and turbine runback occurring at 2.01 EF below the trip setpoint.

f. Anticipated-Transient-without-Scram (ATWS) Mitigation System Actuation Circuitry (AMSAC)

The C-20 permissive will be recalibrated to arm/disarm at the appropriate turbine first stage pressure consistent with the new 0% - 100% power equivalent to nominal turbine first stage pressure range of 0 - 645 psig.

g. P-7 Permissive changes

The P-7 permissive receives input from turbine first stage pressure and power range instrumentation. These inputs will be recalibrated based on the EPU conditions.

h. P-8 Permissive changes

The TS limit for the P-8 will be changed from the current #49% power to –29%.

2. Safety Features Actuation System

a. Main Steam Flow Instrumentation

The main steam flow transmitters will be recalibrated from the current range of 0 to 3.8E6 to 0 to 4.6E6 lbm/hr.

b. Changes to ESFAS Analytical Limits

These parameters and the changes to AL are discussed in Section 3.2.3 of this SER.

3. Control System

a. Turbine first stage pressure instrumentation

The turbine first stage pressure transmitters and associated indications will be recalibrated and scaled to a range of 0 -1000 psig. The input to various control functions such as rod control power mismatch and non linear gain controls, advanced digital feedwater control system, the reference temperature (T_{ref}) input to the reactor coolant T_{avg} control program, and turbine electro-hydraulic control (EHC) will be recalibrated.

b. Control Rod Position Indication

Changes to rod position indication systems, including possible modification to the microprocessor rod position indication (MRPI) and/or plant process computer software, or the MRPI hardware have been assessed to ensure that correct rod position indications are available to the operator.

c. Pressurizer level program

The pressurizer level control system maintains the pressurizer level within a programmed band consistent with a measured value of T_{avg}. For the EPU, the pressurizer level program must be changed from the current 35% - 50% program to a new nominal program of 20% at no load conditions to 54.5% - 57% for full power conditions.

d. Steam Dump Control and Turbine Bypass Systems

The steam dump control system will be changed to decrease turbine operating dead band from 5 EF to 4 EF. In addition to these parameters, (1) proportional gain in percent valve lift per EF and (2) turbine operating - ªT required to modulate valves open and required to snap open valves will be changed.

e. Condensate and Feedwater System Instrumentation

The main feedwater flow transmitters will be replaced and the loop will be recalibrated from the current 0 to 3.8E6 lbm/hr to 0 to 4.6 E6 lbm/hr.

The heater drain pump flow measurement loop will be recalibrated and rescaled from the current 0 to 2.684E6 lbm/hr to 0 to 3.0E6 lbm/hr.

The main feedwater pump suction flow transmitters and control room indicators will be recalibrated and rescaled from the current 0 to 3.5E6 lbm/hr to 0 to 4.6E6 lbm/hr.

The condensate pump discharge pressure alarm and standby pump auto start setpoint are being changed to provide sufficient operating margin.

The condensate booster pump standby pump auto start setpoint is being increased to ensure adequate discharge pressure margin is maintained at EPU.

The main feedwater pump suction pressure setpoint is being changed to provide sufficient net positive suction pressure. Also, a delay is being added to the LP heater bypass valve open circuit to minimize the potential for spurious actuation.

f. Auxliary Feedwater System (AFW) Instrumentation

The SAFW pump flow transmitters will be replaced and flow loop recalibrated for a full scale measurement range of 0 - 300 gpm.

g. SG Level Control

The SG level is controlled by the advanced digital feedwater control system (ADFCS). The ADFCS receives input from the various parameters and ADFCS program software will need to be updated as necessary with the expected EPU values.

h. Turbine Generator Control

The turbine control valve program will be changed from the partial arc emission control to full arc emission control. The turbine control will require calibration with the new turbine first stage pressure range to provide the appropriate valve position feedback and appropriate valve demand and position indication. The mechanical overspeed trip allowable setpoint wil be changed from –110% of rated speed to –109.3% of rated speed. The load drop anticipator circuit will be recalibrated with the EPU power and the reheat crossover pressure to the LP turbines. The reheat pressure will be recalibrated from the current 0 to 125 psig to 0 to 200 psig.

These changes will be made to accommodate the revised process parameters. The staff finds this acceptable because of the fact that these changes are based on the system review and analysis reviewed by the staff (as documented in other sections of this SE) and that the licensee will confirm the acceptability of these changes during power ascension testing. The licensee concluded that when above modifications and changes are implemented, the Ginna instrumentation and control system will accommodate the proposed EPU without compromising safety. None of the above changes affect the licensee's compliance with the existing plant licensing basis, therefore, Ginna continues to meet the current regulatory basis for the plant.

2.4.2 Instrument Setpoint Methodology

In its application and licensing report, the licensee identified that instrument setpoints in the TSs are established using the performance-based setpoint methodology. The NRC staff has previously reviewed this setpoint methodology and found it acceptable for establishing new setpoints in the TSs. The staff therefore, finds this setpoint methodology acceptable in determining new setpoints proposed by the licensee for the power uprate application. These changes are discussed in Section 3.3 of this SE.

The proposed setpoint changes resulting from the EPU are intended to maintain sufficient margin between operating conditions and the trip setpoints and do not significantly increase the likelihood of a false trip or failure to trip upon demand. Therefore, the existing licensing basis is not affected by these setpoint changes to accommodate the power uprate.

Conclusion

The NRC staff has reviewed the licensee's application related to the effects of the proposed EPU on the functional design of the reactor trip system, ESFAS, safe shutdown system, and control systems. The NRC staff concludes that the licensee has adequately addressed the effects of the proposed EPU on these systems and that the changes that are necessary to achieve the proposed EPU are consistent with the plant's design basis. The NRC staff further concludes that the systems will continue to meet the requirements of 10 CFR 50.55a(a)(1), 10 CFR 50.55(a)(h), and GDC 1, 11, 12, 14, 15, 19, 20, 22, 23, 25, 26, 40, and 42. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to instrumentation and controls.

2.5 Plant Systems

2.5.1 Internal Hazards

2.5.1.1 Flooding

2.5.1.1.1 Flood Protection

For proposed power uprates, the NRC staff reviews flood protection measures to ensure that SSCs important to safety are adequately protected from the consequences of internal flooding that result from postulated failures of tanks and vessels, including postulated failure of the main condensor. Because the staff's review focuses on increases of fluid volumes in tanks and vessels that will occur as a result of a proposed power uprate and no changes are being made at Ginna in any areas where safety-related equipment would be affected, an evaluation of this particular area by the NRC staff is not required.

2.5.1.1.2 Equipment and Floor Drains

The function of the equipment and floor drainage system (EFDS) is to assure that waste liquids, valve and pump leakoffs, and tank drains are directed to the proper areas for processing or disposal while preventing a backflow of water that might result from maximum flood levels to areas of the plant containing safety-related equipment and protecting against the potential for inadvertent transfer of contaminated fluids to an uncontaminated drainage system. Because the sources and quantities of liquids that enter the equipment and floor drains will remain unchanged for the proposed power uprate at Ginna and postulated flood levels will not increase, an evaluation of the EFDS is not required.

2.5.1.1.3 Circulating Water System

The circulating water system (CWS) provides a continuous supply of cooling water to the main condenser to remove excess heat from the turbine cycle and auxiliary systems. For proposed power uprates, the NRC staff's review of the CWS focuses on the impact that the proposed uprate will have on existing flooding analyses due to any increases that may be necessary in fluid volumes and installation of larger capacity CWS pumps or piping. Because the impact of the proposed power uprate on the licensee's flooding analysis is considered in Sections 2.5.1.1.1 and 2.5.1.3 of this evaluation, a separate evaluation for the CWS is not required.

2.5.1.2 Missile Protection

2.5.1.2.1 Internally Generated Missiles

Regulatory Evaluation

The NRC staff's review concerns the protection of SSCs important to safety from missiles that could result from in-plant component overspeed conditions and ruptures of high-pressure systems. Potential missile sources include pressurized systems and components, and high-speed rotating machinery. The purpose of the staff's review is to confirm that: (1) SSCs that are important for mitigating accident conditions and the consequences of internally generated missiles are adequately protected from the missile effects, and (2) that failure of other SSCs will not pose a challenge to those SSCs that are being relied upon in this regard. The staff's review focuses on system modifications, increases in system pressures, and component overspeed considerations that could affect the impact that missiles may have on SSCs that are relied upon for event mitigation. The acceptance criteria that are most applicable to the staff's review of internally generated missiles for the Ginna EPU are based on 10 CFR Part 50, Appendix A, GDC 4, "Environmental and Dynamic Effects Design Bases," insofar that SSCs important to safety should be protected from the effects of internally generated missiles; and other licensing-basis considerations that are applicable. The staff's review related to internally generated missiles is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5. Acceptability for EPU operation is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Section 3.5.1 of the Ginna UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

Technical Evaluation

The licensee's evaluation of the impact that EPU will have on the consequences of internally generated missiles is provided in Section 2.5.1.2.1 of the licensing report. The licensee determined that the operating pressures of systems that could generate missiles inside containment will not increase as a result of the proposed EPU and therefore, missile protection considerations and measures that have been taken for protecting equipment inside containment from the effects of missiles will continue to be valid in this regard.

The planned impeller modifications to the feedwater and condensate booster pumps will not result in any missile concerns, as these pumps are not located near any SSCs that are important to safety. The power uprate does not change the characteristics of the potential missile sources that were previously evaluated and, with one exception, no new potential high energy missile sources will be added as a result of the EPU. The one exception is that adding automatic actuation capability to the feedwater isolation valves will require the installation of new high pressure air accumulators. However, in a letter dated March 24, 2006, the licensee indicated that the effects of accumulator ruptures are bounded by previously evaluated failures. Additionally, the licensee indicated that the new accumulators will be positioned in a way that will not impact SSCs important to safety.

The effects of missiles generated by the main turbine on SSCs important to safety is discussed in Ginna UFSAR Section 3.5.1.2.3, "Systematic Evaluation Program Topic III-4," which states that the systems needed for shutting down the plant are either inside or shadowed by the concrete containment building, located below the turbine pedestal, or are outside of the turbine low trajectory missile strike zones. In its March 24, 2006, letter, the licensee indicated that the probability and postulated trajectory of turbine generated missiles is not adversely affected by the proposed power uprate. Consequently, because the EPU does not add any SSCs important to safety that may be impacted by missiles generated by the main turbine, SSCs important to safety will continue to be adequately protected from turbine missiles following the power uprate.

Based upon a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on existing considerations and features that are credited for protecting SSCs from the effects of internally generated missiles. Because SSCs important to safety will continue to be adequately protected from the effects of internally generated missiles, the staff finds that the generation of internally generated missiles will not compromise the licensing-basis capability to safely shut down the plant following EPU implementation.

Conclusion

The NRC staff has reviewed the licensee's assessment of the impact that the EPU will have on the capability to mitigate the effects of internally generated missiles and finds that SSCs important to safety will continue to be adequately protected in this regard after EPU implementation. Therefore, the proposed EPU is considered to be acceptable with respect to the protection of SSCs important to safety from internally generated missiles.

2.5.1.2.2 Turbine Generator

Regulatory Evaluation

The large steam turbines of the main turbine-generator sets have the potential for producing large high-energy missiles. The NRC staff's review of the main turbines focuses on the effects of the proposed EPU on the turbine overspeed protection features to ensure that adequate turbine overspeed protection will be maintained. The acceptance criteria that are most applicable to the staff's review of the turbine generator for the Ginna EPU are based on 10 CFR Part 50, Appendix A, GDC 4, "Environmental and Dynamic Effects Design Bases," insofar that SSCs important to safety should be protected from the effects of turbine missiles; and other licensing-basis considerations that are applicable. The staff's review related to the turbine generator is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5, and acceptability for EPU operation is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Section 3.5.1.2 of the Ginna UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

Technical Evaluation

The licensee's evaluation of the impact that EPU will have on the turbine generator overspeed protective function is provided in Section 2.5.1.2.2 of the licensing report. As provided in the licensee's submittal, the main turbine is provided with two diverse and redundant overspeed protection features: a mechanical overspeed trip mechanism and an electrical overspeed protection system. The mechanical overspeed trip is designed to trip the main turbine to ensure the turbine speed remains less than 120% of the rated design speed. The licensee determined that at EPU conditions the mechanical overspeed trip setpoint needs to be reduced from 110% to 109.3% of the rated design speed. Results from turbine overspeed trip tests that were performed between 1997 through 2005 indicate that the current average mechanical overspeed trip setting is 108.81% (+/- 0.2%) of the rated design value. Since the current setting is less than the new allowable setpoint, the current mechanical overspeed trip setting is acceptable for EPU.

The electrical overspeed protection system consists of the overspeed protection controller (OPC) which is part of the turbine electro-hydraulic control system. The OPC includes a load drop anticipator and an auxiliary governor function. The load drop anticipator logic will rapidly close all control and intercept valves on a complete loss of load, and rapidly close the intercept valves on a partial loss of load. If the auxiliary governor senses an overspeed condition at 103% of the turbine rated design speed, the system will close the reheater intercept valves and modulate the control valves to the closed position until the overspeed condition clears. In the event of a loss of load turbine trip, the main turbine overspeed protection systems ensures that the turbine generator unit will not exceed 120% of the turbine rated design speed.

The licensee performed an analysis to confirm that the increase in power and entrapped steam energy at EPU conditions will not cause the turbine rotor to overspeed beyond the current design limit. Operating at EPU conditions requires replacement of the high pressure turbine with one that has a heavier rotor. The increased inertia from the heavier rotor was considered in the turbine overspeed analysis and the licensee determined that the total increase in inertia due to the heavier high pressure turbine rotor only had a minor impact on the overspeed analysis results.

The Ginna EPU will incorporate a modification to the four (4) high pressure control valves. Essentially, the control valves will be converted to a high lift design. This modification will increase the valve stroke significantly. However, because the most limiting turbine overspeed condition relies upon the turbine stop and intercept valves for isolating steam flow to the main turbine and these valves are not being modified, the modified control valves will have no impact on the maximum turbine overshoot that will occur due to a loss of load event.

The operability and reliability of the turbine overspeed protection system is verified via the performance of routine turbine control valve testing. Neither the test methodology nor the test intervals of the turbine valves will be modified for EPU operation. As discussed in Section 2.12.1.2.3.5 of the licensing report, and as indicated in Table 2.12-2, an overspeed trip test of the turbine will be performed at 20% of the EPU power level to confirm the trip setpoint of the mechanical overspeed trip device. Turbine stop valve, control valve, and intercept valve testing will be performed at 50% of the EPU power level to confirm proper performance.

Based upon a review of the information that was submitted and in consideration of the testing that will be completed to confirm the adequacy of the turbine overspeed protection capability discussed above, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on turbine overspeed protection, including turbine overshoot considerations. The licensee has established a new (lower) mechanical overspeed trip setpoint and has determined that the existing electrical turbine overspeed protection system will remain capable of preventing turbine overspeed consistent with the turbine design criteria. Therefore, the NRC staff agrees that the EPU will not increase the probability that turbine missiles will be generated due to an increased likelihood of turbine overspeed.

The licensee has not requested NRC review and approval of any changes to the licensing basis related to the turbine-generator for EPU operation and this evaluation does not constitute NRC approval of any changes that are being made to the plant licensing basis in this regard.

Conclusion

The NRC staff has reviewed the licensee's assessment of the impact that EPU will have on overspeed protective features that have been provided for the main turbine and finds that existing design features will continue to protect the main turbine from overspeed conditions following postulated transient and accident conditions in accordance with licensing-basis assumptions. Therefore, the proposed EPU is considered to be acceptable with respect to the main turbine.

2.5.1.3 Pipe Failures

Regulatory Evaluation

The failure of high and moderate energy piping can cause pipe whip, jet impingement, and harsh environmental conditions that can result in extensive damage and compromise the capability of SSCs improtant to safety to perform their specified functions. The NRC staff's review for EPUs is concerned with the impact that the proposed power uprate will have on the capability that is credited for mitigating the failure of high and moderate energy fluid piping that is located outside containment and for safely shutting down the plant in accordance with the plant licensing basis. The staff's review focuses on those system modifications and increases in system pressures, temperatures, and flow rates that are necessary in order to implement the EPU in order to confirm that the limitations and assumptions of previous pipe failure analyses remain valid or are otherwise addressed. The acceptance criteria that are most applicable to the staff's review of postulated pipe failures for proposed power uprates are based on 10 CFR Part 50, Appendix A, GDC-4, "Environmental and Dynamic Effects Design Bases," insofar that SSCs important to safety should be designed to accommodate the dynamic effects of postulated pipe ruptures, including the effects of pipe whip and discharging fluids; and other licensing-basis considerations that are applicable. The staff's review associated with postulated pipe failures is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5. Acceptability for EPU operation is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Section 3.6 of the Ginna UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

Technical Evaluation

The licensee's evaluation of the impact that EPU will have on the consequences of high energy line breaks (HELBs) and on moderate energy pipe cracks (MEPCs) is provided in Section 2.5.1.3 of the licensing report. The licensee has determined that because pipe failure evaluations and protective features are based upon system design pressures and these pressures are not affected by EPU, the existing piping failure and effects analyses will continue to be valid following EPU implementation. Similarly, the licensee determined that no new or revised pipe break locations from those previously evaluated will be created. The licensee also evaluated the most limiting pipe failure for each plant area based upon EPU conditions and confirmed that the applicable structural and area design limitations related to temperature, pressure, and flooding would not be exceeded.

Based on a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the consequences of postulated high and moderate energy pipe failures, including flooding considerations. The licensee has determined that EPU will not result in any new pipe failure locations, and the consequences of postulated pipe failures will not exceed plant design limitations that were previously recognized and credited. Therefore, the staff agrees that the capability to mitigate postulated pipe failures in accordance with licensing-basis considerations will not be compromised by EPU operation.

The licensee has not requested NRC review and approval of any changes to the licensing basis for postulated high and moderate energy pipe failures relative to EPU operation and this evaluation does not constitute NRC approval of any changes that are being made to the licensing basis in this regard.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the consequences of postulated high and moderate energy pipe failures and finds that protection of SSCs important to safety from the effects of high and moderate energy pipe failures will continue to satisfy licensing-basis assumptions. Therefore, the proposed EPU is considered to be acceptable with respect to high and moderate energy pipe failure considerations.

2.5.2 Pressurizer Relief Tank

Regulatory Evaluation

The pressurizer relief tank (PRT) is a pressure vessel provided to condense and cool the discharge from the pressurizer safety and relief valves. The tank is designed with a capacity to absorb discharged fluid from the pressurizer relief valves during a specified step-load decrease. The PRT system is not safety-related and is not designed to accept a continuous discharge from the pressurizer. The purpose of the staff's review is to confirm that operation of the PRT will continue to be consistent with the transient analysis of the RCS following implementation of the proposed power uprate, and that failure or malfunction of the PRT will not adversely affect SSCs that are important to safety. The staff's review focuses on any modifications to the PRT and connected piping, and changes related to operational assumptions that are necessary in support of the proposed EPU. In general, the steam condensing capacity of the tank and the tank rupture disk relief capacity should be adequate, taking into consideration the capacity of the pressurizer power-operated relief and safety valves; the piping to the tank should be adequately sized; and systems inside containment should be adequately protected from the effects of HELBs and moderate energy line cracks in the pressurizer relief system. The acceptance criteria that are most applicable to the staff's review of the PRT for proposed power uprates are based on 10 CFR Part 50, Appendix A, GDC 4, "Environmental and Dynamic Effects Design Bases," insofar as it requires that SSCs important to safety be designed to accommodate and be compatible with specified environmental conditions and be protected against dynamic effects, including the effects of missiles; and other licensing-basis considerations that are applicable. The staff's review of the PRT is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5. Acceptability of the PRT for EPU operation is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Section 5.4.8.1 of the Ginna UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

Technical Evaluation

The licensee's evaluation of the impact that EPU will have on the capability of the PRT to accommodate the maximum postulated pressurizer steam discharge is discussed in Section 2.5.2 of the licensing report. The volume of the PRT is 800 ft^3 and its size is based on the requirement to condense and cool a discharge equivalent to 110% of the full power pressurizer steam volume. The licensee indicated that the steam condensing capability of the PRT will continue to satisfy its licensing basis criterion and in particular, it will accommodate the worst-case steam discharge from the pressurizer during EPU operation (which is the loss of external electrical load event).

The PRT normally contains water in a predominantly nitrogen atmosphere, the nitrogen pressure is normally maintained at 3 psig. The licensee has determined that the current PRT water level setpoints assure that adequate coolant is maintained in the PRT to condense and cool the steam that is discharged from the pressurizer and prevent the PRT temperature and pressure from exceeding 200 EF and 50 psig, respectively, at EPU conditions. Additionally, the volume of nitrogen gas in the tank will limit the maximum PRT pressure to 50 psig following a design-basis steam discharge from the pressurizer. A rupture disk that is designed to fail at 100 psig will continue to adequately protect the PRT from excessive pressure in the event of an unforseen pressurizer steam discharge during EPU operation that exceeds the PRT design-basis capability. The rupture disk has a relief capacity in excess of the combined capacity of the pressurizer safety valves. The tank and rupture disk holder are designed for a full vacuum to prevent a tank collapse if the tank contents should cool following a pressurizer steam discharge without nitrogen makeup.

Based on a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the PRT to condense and contain steam that is discharged from the pressurizer safety valves. Because the PRT will remain capable of containing and condensing steam in accordance with desing bais requirements, SSCs important to safety in the vicinity of the PRT will continue to be adequately protected from pressurizer steam discharge events following EPU implementation.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the capability of the PRT to perform its specified function and finds that the PRT will remain capable of condensing and containing steam that is discharged from the pressurizer safety valves, and safety-related SSCs will continue to be protected from PRT failures following postulated transient and accident conditions in accordance with licensing-basis considerations. Therefore, the proposed EPU is considered to be acceptable with respect to the PRT.

2.5.3 Fission Product Control

2.5.3.1 Fission Product Control Systems and Structures

The purpose of the NRC staff's review of fission product control systems and structures is to confirm that current analyses remain valid or have been revised, as appropriate, to properly reflect the proposed EPU conditions. Consequently, the staff's review focuses primarily on any adverse effects that the proposed EPU might have on the assumptions that were used in the analyses that were previously completed. Because the impact of EPU on plant systems and structures identified by the licensee as making up the fission product control system are addressed in Section 2.6, “Containment Review Considerations,” Section 2.7, “Habitability, Filtration, and Ventilation,” and Section 2.9, “Source Terms and Radiological Consequences,” a separate review of this area is not required.

2.5.3.2 Main Condenser Evacuation System

The main condenser evacuation system (MCES) removes non-condensable gases from the condenser to draw a vacuum for plant start up and subsequently maintains condenser vacuum during operation. The MCES consists of two subsystems, the condenser air removal and priming ejectors (hoggers) that initially establish main condenser vacuum and the condenser air removal steam jet air ejectors that are used to maintain condenser vacuum once it has been established. Because the EPU will not cause the existing design capacity of the steam jet air ejectors to be exceeded, the existing capability to monitor the MCES effluent will continue to be adequate. Therefore, NRC review of the MCES for EPU operation is not required.

2.5.3.3 Turbine Gland Sealing System

Regulatory Evaluation

The turbine gland sealing system (TGSS) prevents air leakage into the turbine casing and prevents steam leakage from the turbine casing into the turbine building. The turbine rotor is designed with labyrinth-type seals which provide a high resistance to steam or air flow along the shaft. Gland sealing steam is provided to the turbine gland seal chambers to maintain a positive pressure during plant operating conditions. By design, excess steam leaks from the glands and is collected in the gland steam condenser. Condensed steam drains from the gland steam condenser to the main condenser, where any effluents are monitored for radioactivity. NRC review of the TGSS for EPU operation focuses on any changes in TGSS operation or design that could result in unmonitored effluent releases from the TGSS. The acceptance criteria that are most applicable to the staff’s review of the TGSS for proposed power uprates are based on GDC 60, “Control of Releases of Radioactive Materials to the Environment,” insofar as it specifies that provisions be established for controlling the release of radioactive effluents; GDC 64, “Monitoring Radioactivity Releases,” insofar as it specifies that means be provided for monitoring effluent discharge paths for radioactivity; and other licensing-basis considerations that are applicable. The staff’s review of the TGSS is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5. Acceptability of the TGSS for EPU operation is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Sections 11.5 and 12.5 of the Ginna UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

Technical Evaluation

The licensee’s evaluation of the impact that EPU will have on the TGSS is discussed in Section 2.5.3.3 of the licensing report. The licensee indicated that the turbine gland sealing steam flow rate that is provided from the high pressure turbine control valve steam leak-off and from the high pressure turbine gland steam leak-off will increase for EPU operation. The high-pressure turbine control valves will be modified to a "high lift" design and changed from partial to full arc admission in order to support EPU operation. These modifications will increase the amount of steam leak-off flow by about 5% per valve. However, the licensee determined that the increase in steam flow to the gland steam condenser is relatively small and does not exceed its design capacity. Consequently, existing provisions for monitoring effluent from the gland steam condenser are not affected by EPU.

Relative to steam leak-off flow from the high pressure turbine steam glands, the licensee indicated that the leak-off flow will increase for EPU operation as a consequence of the higher turbine exhaust pressure that will exist. While this leak-off steam is used to supply sealing steam for the low pressure turbines, the increased amount may be excessive and a bypass line to the main condenser may be required to handle the excess volume. Since the bypass line (should it be needed) will direct any excess steam flow from the high pressure turbine glands to the main condenser, no new TGSS release paths will be established and existing provisions that have been established for monitoring effluent from the main condenser for radioactivity will continue to be sufficient in this regard.

Based on a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed EPU on the TGSS. The licensee’s evaluation indicates that existing provisions that have been established for monitoring TGSS effluents for radioactive materials will continue to be adequate following EPU implementation and therefore, the staff agrees that the EPU will not result in unmonitored effluents from the TGSS.

The licensee has not requested NRC review and approval of any changes to the TGSS licensing basis relative to EPU operation and this evaluation does not constitute NRC approval of any changes that are being made to the licensing basis in this regard.

Conclusion

The NRC staff has reviewed the licensee’s assessment of operational and design changes being made to the TGSS for the EPU and finds that existing plant design features will continue to monitor TGSS effluent releases in accordance with licensing-basis assumptions. Therefore, the proposed EPU is considered to be acceptable with respect to the TGSS.

2.5.4 Component Cooling and Decay Heat Removal

2.5.4.1 Spent Fuel Pool Cooling System

Regulatory Evaluation

The spent fuel pool (SFP) provides wet storage of the spent fuel assemblies. The spent fuel pool cooling system (SFPCS) consists of one primary SFP cooling loop and two backup SFP cooling loops. The primary SFP cooling loop (SFP loop B) is made up of SFP pump B, SFP heat exchanger B, and related piping. The backup SFP cooling loops include installed SFP loop A, which is made up of SFP pump A, SFP heat exchanger A, and related piping; and the SFP standby loop, which is normally not installed and is made up of a SFP standby pump, SFP standby heat exchanger, and hoses. Each of the backup SFP cooling loops are able to accommodate about 50% of the heat load that can be accommodated by the primary SFP cooling loop. The safety function of the SFPCS is to cool the spent fuel assemblies and keep the spent fuel assemblies covered with water during all storage conditions. The NRC staff’s review for proposed power uprates focuses on the capability of the SFPCS to accommodate the additional heat load that will result from EPU operation in accordance with the SFPCS licensing basis. The GDC that are most applicable to the staff's review of the SFPCS for the Ginna EPU are GDC 44, "Cooling Water," insofar as it specifies that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided; and GDC 61, "Fuel Storage and Handling and Radioactivity Control," insofar as it specifies that fuel storage systems be designed with residual heat removal capability that is commensurate with the safety function being performed. The staff's review of the SFPCS is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5, and acceptability of the SFPCS for EPU operation is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Section 9.1.3 of the Ginna UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

Technical Evaluation

The specific SFPCS considerations that are likely to be impacted by the proposed power uprate include:

12. The capability to remove the decay heat produced from a full core offload. The maximum SFP temperature is not allowed to exceed 150 EF.

13. The capability to remove the decay heat produced from a normal (refueling) core offload (typically 44 to 45 fuel assemblies). The maximum SFP water temperature is not allowed to exceed 150 EF.

14. The time it takes to reach 180 EF (SFP structural temperature limit) upon a complete loss of SFP cooling, assuming that the initial SFP temperature is 150 EF.

15. The SFP boil-off rate and the capability to provide sufficient makeup upon a complete loss of SFP cooling.

The licensee's evaluation of the impact that EPU will have on the SFPCS is provided in Section 2.5.4.1.2 of the licensing report. Because the licensee uses administrative controls to establish how soon after reactor shutdown fuel can be moved to the SFP based upon the maximum SFP heat load that is allowed, the capability of the SFPCS to remove the decay heat produced from normal and full core offloads will continue to be assured. Presently, the actual number of spent fuel rack storage positions that are installed in the SFP is 1321. Although the Ginna TSs allow 1879 spent fuel assemblies to be stored in the SFP (accomplished by fuel rod consolidation and the installation of SFP wall mounted racks), the licensee plans to implement on-site dry cask storage around 2009 to accommodate the fuel off-loads through the Ginna license expiration date in 2029. The licensee evaluated the capability of the SFPCS to accommodate the total amount of decay heat following the last full core offload at the end of plant life, with the last and most recent offloads occupying the 1321 fuel storage positions that are available in the SFP and the oldest core offloads relocated to the dry storage casks. Depending on the lake water temperature, the delay time for the last core offload could be as much as 20 days before the decay heat load is reduced to within the capacity of the SFPCS such that the 150 EF temperature limit will not be exceeded. However, because there is no urgency in offloading the core, the delay time that is required is inconsequential.

The licensee's evaluation of the worst-case loss of SFP cooling shows that it could take as little as 2.4 hours for the SFP temperature to reach the structural temperature limit of 180 EF. However, following a loss of cooling from the "B" SFP cooling loop, the "A" SFP cooling loop heat exchanger can be made operational within 45 minutes as discussed in UFSAR Section 9.1.3.4.3. Following initiation of cooling by heat exchanger A, the SFP heat up rate will be decreased by approximately 50% and the time available before the SFP temperature exceeds 180 EF will be increased to at least 5.2 hours. Since the SFP standby pump can be placed in service within 3 hours and it is capable of accommodating the remaining decay heat load, the SFP structural temperature limit of 180 EF will not be exceeded.

The licensee's evaluation of the worst-case required SFP makeup rate following a complete loss of SFP cooling could be as much as 52.8 gpm. As discussed in Section 2.5.4.1 of the licensing report, a makeup water flow rate of 60 gallons per minute can be made available from the refueling water storage tank in less than 15 minutes. As an alternative, 50 gallons per minute of water from the chemical and volume control system hold up tanks can also be made available in approximately 15 minutes. Because the alternate makeup capability is not quite adequate for the worst-case boil-off rate of 52.8 gallons per minute, the licensee indicated that the off-load time can be delayed until the boil-off rate is reduced to less than 50 gallons per minute. In a letter dated November 3, 2005, the NRC staff requested that the licensee address the reduced make-up capability to the SFP. In its December 19, 2005, letter, the licensee stated that during the worst-case scenario, it would take approximately 5 hours for the SFP water to heat up to 212 EF. Furthermore, it would take an additional 14 hours for the SFP boil-off rate to decrease to 50 gpm. The licensee calculated that during this time, the SFP water level would drop less than 2 inches. Ginna TS 3.7.11 requires the water level in the SFP to be 23 feet above the top of the irradiated fuel assemblies and therefore, a decrease in the SFP water level of 2 inches is considered to be negligible. Furthermore, the action requirements of TS 3.7.11 will apply until the SFP water level is fully restored to the minimum required level. In a letter dated March 24, 2006, the licensee stated that the Ginna UFSAR will be revised to reflect this change in the plant licensing basis within 6 months of implementing the EPU. This is considered to be acceptable to the NRC staff because the required water level above the fuel will be maintained by compliance with the TSs.

Current TS 4.3.3 states that the spent fuel pool is designed and shall be maintained with a storage capacity limited to no more than 1879 fuel assemblies and 1369 storage locations. This is inconsistent with the licensee's EPU evaluation which is based upon the worst-case decay heat load that is generated from 1321 fuel assemblies, assuming that on-site dry cask storage will be used for the remaining (older) fuel assemblies. In its March 24, 2006, letter, the licensee committed to submit a proposed change to TS 4.3.3 that would revise the number of fuel assemblies that are allowed to be stored in the SFP to 1321 prior to startup for EPU operation. The NRC staff finds this acceptable because the number of fuel assemblies will be administratively controlled by the licensee and the current SFP loading is below this limit.

Based upon a review of the information that was provided, and in consideration of the licensee's commitments to revise TS 4.3.3 and the UFSAR as discussed above, the staff agrees that operation of the plant at the proposed EPU power level will not adversely impact the capability to: a) remove decay heat from the SFP following normal and full core offloads, b) establish alternate SFP cooling that is sufficient to maintain the SFP temperature below its structural temperature limit of 180 EF in the event that the operating SFPCS train should become inoperable, and c) provide sufficient makeup to the SFP from both the normal and alternate water sources for maintaining the SFP water level should a complete loss of all SFP cooling occur.

The licensee has not requested NRC review and approval of any changes to the SFPCS licensing basis relative to EPU operation and, with the exception of the alternate SFP makeup considerations discussed above, this evaluation does not constitute NRC approval of any changes that are being made to the SFPCS in this regard.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the SFPCCS and finds that the SFPCCS will continue to provide sufficient SFP cooling and that the SFP makeup capability will continue to be adequate in accordance with licensing-basis considerations (as modified). Therefore, the proposed EPU is considered to be acceptable with respect to the SFPCCS and associated SFP makeup capability.

2.5.4.2 Station Service Water System

Regulatory Evaluation

The service water system (SWS) takes suction from Lake Ontario and provides essential cooling to safety-related equipment and also provides cooling to non-safety-related auxiliary components that are used for normal plant operation. The SWS consists of four service water pumps, a single loop supply header, isolation valves, and a normal and standby discharge header. The physical design of the SWS is such that one service water pump from each Class 1E electrical train is arranged on each of the two discharge headers which then supplies the service water loop header. The safety function of the SWS is to provide sufficient cooling water flow to critical plant loads for mitigating abnormal and accident conditions. The NRC staff's review for proposed power uprates focuses on the impact that the proposed EPU will have on the capability of the SWS to perform its specified functions in accordance with the plant licensing basis. The criteria most applicable to the staff's review of the SWS are based primarily on GDC-44, "Cooling Water," insofar that it specifies that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided; and other licensing-basis criteria that are applicable. The staff's review of the SWS is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5, and acceptability of the SWS for EPU operation is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Section 9.2.1 of the Ginna UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

Technical Evaluation

The licensee's evaluation of the impact that EPU will have on the SWS is provided in Section 2.5.4.2.2 of the licensing report. As discussed in this report, the licensee evaluated the capability of the SWS to perform its specified functions following implementation of the proposed power uprate. The licensee determined that the majority of the components served by the SWS are unaffected by EPU conditions since their functions and heat removal requirements are unrelated to reactor power level or turbine cycle performance. The components of regulatory significance that are affected by the EPU include the component cooling water heat exchangers, the spent fuel pool heat exchangers, and the containment recirculation fan coolers. While the increased heat loads that result due to EPU operation will cause the service water outlet temperatures for these components to be higher, the licensee found that the existing temperature limitations will not be exceeded during postulated worst-case scenarios and will continue to satisfy the existing design specifications. The licensee's evaluation for EPU operation credits the flow from two service water pumps for removing the heat from the containment recirculation fan coolers following a LOCA, whereas the flow from only one service water pump was credited for the current licensed power level. The licensee indicated that the basis for the SWS TS requirement will be revised to reflect the requirement that two service water pumps must be operable in each train in order for the SWS to be operable. Attachment 9 to the July 7, 2005, application includes a commitment by the licensee to complete this action prior to plant startup from the fall 2006 refueling outage.

The licensee evaluated the impact of the proposed EPU on the resolution of the GL 96-06 waterhammer and two-phase flow issues. Because the licensee's analysis found that the maximum containment temperature will be slightly lower for EPU conditions than the maximum temperature that was assumed for the current licensed power level, the licensee concluded that the resolution of GL 96-06 with respect to waterhammer and two-phase flow will continue to be valid for EPU operation.

The licensee also evaluated the impact of the proposed EPU on the programs, procedures, and activities that have been established for resolving the GL 89-13 service water issues. Because the SWS is not being modified for EPU operation and it will continue to function in accordance with its original design provisions and limitations, the licensee concluded that resolution of the GL 89-13 service water issues for Ginna will continue to be valid and programmatic controls will continue to assure that heat exchanger performance is maintained consistent with the plant licensing-basis following the proposed power uprate.

Based upon a review of the information that was submitted, and in consideration of the licensee's commitment to revise the basis for the Ginna TS for SWS operability to be consistent with the EPU analysis that was completed as discussed above, the staff is satisfied that operation of the plant at the proposed EPU power level will not adversely impact the capability of the SWS to perform its specified functions because the heat transfer is adequate to support its design and analysis requirements. The licensee has also confirmed that the proposed EPU will not adversely affect resolution of the GL 96-06 waterhammer and two-phase flow issues or the resolution of the GL 89-13 service water issues.

The licensee has not requested NRC review and approval of any changes to the SWS licensing basis relative to EPU operation and, with the exception of the number of service water pumps that must be credited for accident mitigation discussed above, this evaluation does not constitute NRC approval of any changes that are being made to the SWS in this regard.

Conclusion

The NRC staff has reviewed the licensee's assessment of the impact that the proposed EPU will have on the SWS and finds that the SWS will continue to be capable of performing its specified functions in accordance with licensing-basis considerations. Therefore, the proposed EPU is considered to be acceptable with respect to the SWS.

2.5.4.3 Component Cooling Water System

Regulatory Evaluation

The component cooling water system (CCWS) circulates water to remove heat from plant components during plant operation, plant cooldown, and post accident conditions. The system consists of two pumps, two heat exchangers, a surge tank, and necessary piping and valves. Some of the major safety-related components that are cooled by the CCWS include the emergency core cooling system equipment, ventilation equipment, and reactor shutdown equipment. The NRC staff's review for proposed power uprates focuses on the continued capability of the CCWS to provide sufficient cooling water for critical plant loads in accordance with the CCWS licensing basis. The criteria most applicable to the staff's review of the CCWS are based primarily on GDC-44, "Cooling Water," insofar that it specifies that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided; and other licensing-basis criteria that are applicable. The staff's review of the SWS is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5, and acceptability of the SWS for EPU operation is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Section 9.2.2 of the Ginna UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

Technical Evaluation

The licensee's evaluation of the impact that EPU will have on the CCWS is provided in Section 2.5.4.2.3 of the licensing report. As discussed in this report, the licensee evaluated the impact of the proposed EPU on the capability of the CCWS to perform its specified functions following the proposed power uprate. The licensee determined that the existing component cooling water (CCW) flow rates will continue to be sufficient for performing the required cooling and decay heat removal functions, and that no system modifications are required for EPU operation. The licensee found that during normal plant full power operation, the heat loads from the cooled components are not significantly different from the pre-EPU heat loads and consequently, the impact on the CCWS is minimal. However, during normal plant cooldown, the EPU heat loads are higher due to the increased reactor decay heat that results from EPU operation. Because the reactor coolant system cooldown rate and the maximum allowed CCW heat exchanger outlet temperature are both limited by operating procedures and these limitations are not being changed for EPU, CCWS design limitations will not be exceeded. The licensee also confirmed that the capability of the CCWS exceeds the demands that will be placed on the system for accident mitigation and post-accident recirculation/decay heat removal functions following the proposed power uprate. The licensee determined that the increased CCW system volume that results during EPU operation due to the slightly higher temperature conditions is less than 300 gallons; well within the 1000 gallon surge volume that is available in the CCW surge tank.

The licensee evaluated the cooldown capability of the RHR/CCW System for various cooldown scenarios and determined that for cooldown scenarios with early entry into RHR shutdown cooling (4 to 6 hours after reactor shutdown) with a maximum RCS cooldown rate, the CCW temperature leaving the RHR heat exchanger could exceed 170 EF which is the present maximum temperature assumed in the thermal stress analysis of CCW piping at the RHR heat exchanger outlet. With respect to normal plant cooldown evolutions, the licensing report indicates that administrative controls will be used to limit the CCW outlet temperature from the residual heat removal (RHR) heat exchangers to 170 EF following EPU implementation. Also, training will be provided to the plant operators on this issue as part of the overall training to address the impact of EPU on plant operations. Based on this, the licensee determined that for the worst-case accident condition, the CCW temperature leaving the RHR heat exchanger would not reach the maximum temperature of 170 EF and therefore, the worst-case accident condition remains bounded by the previous analysis.

Section 9.2.2.4.1.6 of the Ginna UFSAR discusses analyses that the licensee has performed to minimize the potential for flow-induced vibration in the CCW and RHR heat exchangers. Based on these analyses, the licensee determined that limiting CCW flow to approximately 2500 gallons per minute through the shell side of each CCW heat exchanger would provide acceptable performance. In a letter dated December 19, 2005, the licensee clarified that because the power uprate will not result in an increase in the maximum required CCW flow through either the RHR or the CCW heat exchangers, the CCW flow limitations discussed in the Ginna UFSAR will continue to be satisfied following EPU implementation.

Due to the increase in decay heat associated with the EPU, the licensee performed an analysis to determine the capability of the CCW System to cool the plant to cold shutdown conditions within 72 hours as required by Appendix R. The analysis determined that the ability to reach cold shutdown conditions within 72 hours was still satisfied as long as the initiation of RHR cooling occurred no later than 60 hours following initial plant shutdown. Therefore, EPU does not impact the capability of the Ginna CCW System to cool the plant to a cold shutdown condition with 72 hours for those Appendix R events where the CCW System is relied upon for achieving cold shutdown.

Based upon a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the CCWS to perform its specified functions. The licensee has confirmed that the EPU will not cause CCWS design limitations to be exceeded and that the capability to cool down the RCS in accordance with the plant licensing basis will not be affected by the proposed power uprate. The staff's evaluation of GL 89-13 and GL 96-06 considerations applies primarily to the SWS and is discussed in the previous section.

The licensee has not requested NRC review and approval of any changes to the CCWS licensing basis relative to EPU operation and this evaluation does not constitute NRC approval of any changes that are being made to the CCWS in this regard.

Conclusion

The NRC staff has reviewed the licensee's assessment of the impact that the proposed EPU will have on the CCWS and finds that the CCWS will continue to be capable of performing its specified functions in accordance with licensing-basis considerations. Therefore, the proposed EPU is considered to be acceptable with respect to the CCWS.

2.5.4.4 Ultimate Heat Sink

The ultimate heat sink (UHS) provides the cooling medium for dissipating the heat removed from the reactor and its auxiliaries during normal operation, refueling, and accident conditions. Lake Ontario serves as the UHS for the Ginna plant and because its cooling capacity far exceeds the shutdown cooling and accident heat loads for Ginna, it is unaffected by the proposed power uprate. Therefore, an evaluation of the UHS is not required.

2.5.4.5 Auxiliary Feedwater System

Regulatory Evaluation

In conjunction with a seismic Category 1 water source, the auxiliary feedwater system (AFWS) is an engineered safety feature that functions to supply feedwater to the steam generators for removing reactor decay heat when the main feedwater system is not available. The Ginna AFWS consists of the normal (preferred) AFWS (2 motor driven and a turbine driven pump) and a backup (standby) AFWS (2 motor driven pumps). The preferred AFWS is automatically actuated to provide makeup water to maintain steam generator water levels for dissipating reactor decay heat whenever the feedwater system is not available. The standby auxiliary feedwater system is capable of being brought into service by operator action from the control room, and it was installed to provide an independent system capability following a high-energy line break event which could render inoperable the three preferred auxiliary feedwater pumps. Initiation of auxiliary feedwater flow to the steam generators can be delayed by up to 10 minutes during a design-basis accident or transient with acceptable results. The NRC staff's review of the AFWS for EPUs focused primarily on the capability of the AFWS to provide sufficient emergency feedwater flow to accommodate the increased decay heat load for the uprated plant consistent with licensing-basis considerations. The staff also reviews the effects of the proposed EPU on the likelihood of creating fluid flow instabilities (such as waterhammer) during AFWS operation. The acceptance criteria that are most applicable to the staff's review of the AFWS for proposed power uprates are based upon 10 CFR Part 50, Appendix A, GDC 34, "Residual Heat Removal," insofar that an RHR system should be provided to transfer fission product decay heat and other residual heat from the reactor core; GDC 44, "Cooling Water," insofar that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions should be provided; and other licensing-basis considerations that are applicable. The staff's review of the AFWS is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5. Acceptability is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Section 10.5 of the Ginna UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

Technical Evaluation

The licensee's evaluation of the impact that EPU will have on the AFWS is provided in Section 2.5.4.5 of the licensing report. As discussed in the licensing report and summarized in Table 2.5.4.5-1 of that report, the licensee evaluated the impact of the proposed EPU on the capability of the AFWS to perform its specified functions following the proposed power uprate. The licensee determined that for EPU conditions, the minimum required flow rate of the preferred AFWS for a loss of normal feedwater, station blackout, anticipated transient without scram (ATWS), and for a normal plant cooldown remain bounded by the current analyses. For these events, while the time to cool down the plant will increase for EPU conditions due to the increased reactor decay heat, the licensee determined that specified cooldown times would not be exceeded.

The licensee also determined that, for the most limiting case as established by a main feedwater line break event, the minimum flow required from a standby AFWS pump for EPU operation will increase from the current value of 200 gpm to 235 gpm. The licensee has confirmed that the standby AFWS pumps are capable of providing this additional flow due to the available margin in pump design, but it will be necessary to modify the valve trim for the standby AFWS pump flow control valves in order to minimize the system pressure drop at the higher flow rate. As discussed in Section 2.12.1.2.5 of the licensing report, and as indicated in Table 2.12-5, the capacity of the standby AFW system will be verified during EPU startup testing prior to exceeding 1520 MWt.

The AFWS normally takes water from two condensate storage tanks, and the service water system provides an alternate safety-related source of water for the AFWS. Because the AFWS flow requirement is relatively small compared to the capacity of the service water system, the licensee concluded that this alternate water supply will remain capable of providing the required flow rate to support the AFWS following EPU implementation.

The current TS-required volume for the condensate storage tanks is 22,500 gallons. Following EPU implementation, taking into consideration the unusable height of water above the tank outlet that is needed to prevent vortexing and considering measurement uncertainties, the licensee has determined that the required volume will increase to 24,350 gallons. The licensee indicated that the condensate storage tank overflow piping will be modified in order to accommodate this increased volume requirement.

Based upon a review of the information that was submitted, and in consideration of testing that will be completed to confirm the capability of the standby AFWS to provide SG makeup water as discussed above, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the AFWS to perform its specified functions. Because the required increase in AFWS flow rates for EPU conditions will not exceed the design capability of the AFWS pumps, including alternate safety-related makeup capability, and no major changes are being made to the AFWS design, fluid flow instabilities and waterhammer should not occur as a result of the proposed power uprate.

The licensee has not requested NRC review and approval of any changes to the AFWS licensing basis relative to EPU operation that are included within the scope of this evaluation section and consequently, this section of the evaluation does not constitute NRC approval of any changes that are being made to the AFWS in this regard.

Conclusion

The NRC staff has reviewed the licensee's assessment of the impact that the proposed EPU will have on the AFWS and finds that the AFWS will continue to be capable of performing its specified functions in accordance with licensing-basis considerations. Therefore, the proposed EPU is considered to be acceptable with respect to the AFWS.

2.5.5 Balance-of-Plant Systems

2.5.5.1 Main Steam

The main steam supply system (MSSS) transports steam from the NSSS to the power conversion system and to various auxiliary steam loads. The NRC staff's review of the MSSS for proposed power uprates evaluates system design limitations to assure that reactor safety will be preserved. This section of the safety evaluation focuses primarily on any changes in the design or operation of the MSSS that could impact the capability of steam-driven equipment to function in accordance with safe shutdown and accident analysis assumptions, impact the capacity of the steam dump system, or could otherwise result in increased challenges to reactor safety systems. Because no changes of this nature are being made, evaluation of the MSSS is not required.

2.5.5.2 Main Condenser

The main condenser is designed to condense and deaerate the exhaust steam from the main turbine and provide a heat sink for the turbine bypass system (TBS). For PWRs, the NRC staff's review of the main condenser for proposed power uprates focuses primarily on the impact that EPU will have on the extent and consequences of flooding that will occur as a result of a postulated failure of the main condenser. Because flooding considerations are evaluated in Section 2.5.1.1.1 of this safety evaluation, which includes consideration of flooding due to failure of the main condenser, a separate evaluation of the main condenser in this section is not required.

2.5.5.3 Turbine Bypass

The TBS is a non-safety-related system designed to discharge a percentage of rated main steam flow directly to the main condenser, thereby bypassing the turbine and enabling the plant to take step load reductions up to the capacity of the TBS without causing the reactor to trip. This section of the safety evaluation focuses primarily on any changes in the design and operation of the TBS that could compromise its capability to perform its specified functions, thereby increasing the potential for increased challenges to reactor safety systems. Because changes are not being made in the design and operation of the TBS in this regard, an evaluation of the TBS is not required.

2.5.5.4 Condensate and Feedwater

Regulatory Evaluation

The condensate and feedwater system (CFS) provides feedwater at the appropriate temperature, pressure, and flow rate to the steam generators (SGs). The only part of the CFS that is classified as safety-related is the feedwater piping from the SGs up to and including the outermost containment isolation valves. The NRC staff's review of the CFS for proposed power uprates focused primarily on system design limitations and reductions in operational flexibility that could result in increased challenges to reactor safety systems, such as creating unacceptable fluid flow instabilities. The acceptance criteria that are most applicable to the staff's review of the CFS for proposed power uprates are based primarily upon existing plant licensing-basis considerations, especially with respect to maintaining CFS reliability and minimizing challenges to reactor safety systems during EPU operation. The staff's review of the CFS is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5. Acceptability is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Sections 10.4.4 and 10.4.5 of the Ginna UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

Technical Evaluation

The licensee's evaluation of the impact that EPU will have on the CFS is provided in Section 2.5.5.4 of the licensing report. As discussed in this report, the licensee has evaluated the capability of the CFS to supply feedwater to the steam generators for the proposed power uprate conditions and has determined that the existing CFS is capable of performing this function. The licensee also confirmed that EPU operating conditions will not exceed the design capability of the feedwater flow venturis and therefore, feedwater flow rate measurements for power level determinations will continue to be accurate.

In order to provide the higher condensate and feedwater flow rates that are necessary for the uprated power level, the condensate booster pumps will be modified with new pump motors and impellers, and the pump casings will be modified to accommodate the new impellers. The feedwater pumps will be modified with new pump motors and impellers, and the valve trim for the feedwater regulating valves will be modified to accommodate the higher feedwater flow rate for EPU operation.

Because the Ginna CFS has two 50% capacity feedwater pumps, a trip of one pump will result in a reactor trip (either due to low steam generator level, or due to operator action). The CFS has three 50% capacity condensate pumps and condensate booster pumps and a failure of one pump will typically not result in a reactor trip because the standby pump will automatically start. Post-EPU plant operation will be the same in this regard, but the higher feedwater flow rate that is required for EPU operation could cause instability in CFS performance during spurious actuation of the low pressure (LP) heater bypass valve or following the loss of a condensate pump, condensate booster pump or heater drain pump. In order to minimize the potential for unsuitable hydraulic instabilities and to provide for reliable CFS operation following EPU implementation, the licensee will make the following setpoint changes:

(1) The main feedwater pump suction pressure setpoint that provides the pump start permissive and auto open signal to the low pressure (LP) heater bypass valve will be

changed to provide the required margin for feedwater pump net positive suction pressure (NPSH) at the uprated feedwater flows consistent with the design of the replacement main feedwater pump impellers. In addition, a delay will be added to the LP heater bypass valve open circuit to minimize the potential for spurious actuation and resultant condensate and feedwater system instability associated with events such as a loss of a condensate pump, condensate booster pump or heater drain pump.

(2) The main feedwater pump NPSH calculator setpoint which provides an alarm and also opens the LP heater bypass valve on low NPSH will be reset to provide the required margin for feedwater pump NPSH at the uprated feedwater flow rate consistent with the design of the replacement main feedwater pump impellers. As with the main feedwater pump low suction pressure signal, the signal to the LP heater bypass valve will be delayed to minimize the potential for spurious actuation and resultant condensate and feedwater system instability associated with events such as a loss of a condensate pump, condensate booster pump or heater drain pump.

During a telephone call with the licensee on March 2, 2006, the NRC staff requested that the licensee provide additional information to explain why it was not considered necessary to perform transient testing of the CFS pumps to confirm that the established setpoints will provide acceptable and reliable operation of the CFS, thereby minimizing any increase in challenges to safety systems following EPU implementation. The licensee provided its response in a letter dated March 24, 2006. The licensee indicated that the overriding design objective of the EPU was to maintain or improve plant reliability as compared to the pre-EPU condition. To this end, the CFS design and setpoint changes were engineered to minimize any changes in the plant response to CFS transients. Historically, one cause of pump trips has been due to motor failure. The licensee has established ongoing inspection and maintenance programs to maintain the reliability of CFS pump motors and continued implementation of this program following the power uprate will assure reliable operation of the CFS pump motors. The licensee indicated that a detailed thermal-hydraulic model of the CFS has been developed and benchmarking shows excellent correlation between the model and actual plant data. The model has been modified to represent EPU conditions, including consideration of the new pump performance curves and flow characteristics of the replacement feedwater regulating valves. Factory testing of the new pump impellers will validate the design curves that are used in the model. Also, one of the three new condensate booster pumps was installed in the 2005 refueling outage and pump performance is as expected when compared to CFS model predictions. As discussed in Sections 2.12.1.2.3.5 and 2.12.1.2.4 of the licensing report and as indicated in Tables 2.12-2 and 2.12-3, the power ascension test program will validate CFS model predictions for steady state conditions and some limited transient testing will be completed to confirm the dynamic response of the CFS and digital feedwater control capability. The transient tests will be performed at 30 percent and 100 percent EPU power, while steady state conditions will be monitored over the full range of EPU power operation. Given these considerations, and because no new protective or control functions are being implemented and trip testing of the CFS pumps was not required for the original plant startup test program, the licensee concluded that specific transient testing for the CFS pumps is not necessary for the Ginna EPU. The NRC staff finds this acceptable since the operation of the CFS will be adequately monitored during the power ascension and no new protective or system control functions were required.

In order to mitigate a design-basis steam line break in containment during EPU operation with an assumed failure of the main feedwater regulating valves to close, the licensee will credit automatic isolation of the feedwater isolation valve for the faulted SG. Currently, these valves are manually operated and the licensee will install safety-related, automatically actuated valve operators in order to perform this function. The new valve operators are designed to fully close the feedwater isolation valves within 30 seconds in order to satisfy the EPU accident analysis assumptions for a main steam line break inside containment. Because the valve closure time is well in excess of 5 seconds, the licensee does not believe that automatic closure of these valves during EPU conditions will cause a waterhammer to occur. The licensee's request for NRC review and approval to credit automatic closure of the main feedwater isolation valves was submitted as a separate amendment application dated April 29, 2005, and NRC review of the licensee's request is not included within the scope of this evaluation.

Based upon a review of the information that was submitted, and in consideration of testing that will be performed as discussed above, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability and reliability of the CFS to provide feedwater to the steam generators following EPU implementation. Based upon CFS model predictions, modifications to the feedwater regulating valves, condensate booster pumps, and feedwater pumps should provide sufficient margin to accommodate the increased feedwater flow requirements for EPU operation, and related setpoint changes should provide for reliable performance during CFS transient conditions. Any problems with CFS performance or hydraulic instability will be identified during the power ascension and transient testing program discussed above. For the reasons that were provided by the licensee in the March 24, 2006, letter, the NRC agrees that specific transient testing of the CFS pumps is not necessary for EPU implementation. Should transient performance of the CFS following a CFS pump trip not be entirely as expected, the safety-related auxiliary feedwater system will be available for providing steam generator makeup and any necessary adjustments to the CFS control settings can be made at that time to assure that long-term CFS operation will be sufficiently reliable at the uprated power level.

The licensee has not requested NRC review and approval of any changes to the CFS licensing basis relative to EPU operation and this evaluation does not constitute NRC approval of any changes that are being made to the licensing basis in this regard. The licensee's proposal to credit automatic isolation of the feedwater isolation valves was submitted as a separate amendment application dated April 29, 2005, and this change to the plant licensing basis is not included within the scope of this evaluation.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the CFS and finds that the CFS will remain capable of providing feedwater to the steam generators without creating unacceptable fluid flow instabilities and increased challenges to safety systems. Also, EPU steady-state and power ascension testing will provide assurance that problems of this nature will not be introduced by the proposed power uprate. Therefore, the CFS will continue to satisfy licensing-basis considerations and the proposed EPU is considered to be acceptable with respect to the CFS.

2.5.6 Waste Management Systems

2.5.6.1 Gaseous Waste Management Systems

Regulatory Evaluation

Gaseous waste management systems (GWMS) involve the gaseous radwaste system, which deals with the management of radioactive gases collected in the offgas system or the waste gas storage and decay tanks. The GWMS collects gas from the gas stripper, volume control tank, sampling system, chemical and volume control system, spent resin storage tank, gas analyzer, gas decay tank, pressurizer relief tank, reactor coolant drain tank, and charging pump leakoff collection tank. The system is also designed to compress the gas that is collected and store it in gas decay tanks, sample and analyze the gas prior to release, supply nitrogen to various components as a cover gas, and supply hydrogen to the volume control tank to maintain hydrogen partial pressure to compensate for the hydrogen that dissolves in the reactor coolant. The NRC staff's review of the GWMS focused on the effects that the proposed EPU may have on methods of treatment; expected releases; principal parameters used in calculating releases of radioactive materials in gaseous effluents; and the accumulation and management of explosive mixtures. The acceptance criteria for the GWMS that are most applicable to the staff's review of proposed power uprates are based upon (1) 10 CFR 20.1302, insofar as it places specific limitations on the annual average concentrations of radioactive materials released at the boundary of the unrestricted area; (2) GDC 60, "Control of Releases of Radioactive Materials," insofar as it specifies that the plant design include means to control the release of radioactive effluents; (3) GDC 61, "Fuel Storage and Handling and Radioactivity Control," insofar as it specifies that systems that contain radioactivity be designed with suitable shielding and filtration; (4) 10 CFR Part 50, Appendix I, Sections II.B, II.C, and II.D, which set numerical guides for meeting the "as low as is reasonably achievable" criterion; and (5) other licensing-basis considerations that apply. The staff's review of the GWMS was performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5. Acceptability is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Section 11.3 of the Ginna UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

Technical Evaluation

The licensee's evaluation of the impact that EPU will have on the GWMS is provided in Section 2.5.6.1 of the licensing report. The licensee determined that the proposed power uprate will not significantly increase the amount of gas that is normally processed by the GWMS, require any changes in the operation or design of equipment used in the GWMS, radiological and environmental monitoring of the waste streams will not be affected, and no new or different radiological release paths will be introduced as a result of the proposed power uprate. The licensee confirmed that the GWMS will remain capable of processing the increased radioactive nuclide concentrations that will exist during EPU operation. Additionally, the licensee concluded that the EPU will not add or change any source of potentially explosive mixtures. Since the design and operation of the GWMS will not change, the increased nuclide concentrations will not exceed the capability of the GWMS to process waste, the volume of gas flowing into the gaseous radwaste system will not increase significantly, and no new explosive mixtures will be introduced as a result of the EPU, the licensee concluded that the capability of the GWMS will continue to be adequate.

Based upon a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the GWMS to perform its specified functions. Because the amount of gaseous waste will not exceed the design capacity of the GWMS, the capability to monitor effluents will not be affected, and existing design features will continue to assure that explosive concentrations of hydrogen will not accumulate, the staff agrees that the GWMS will continue to satisfy the plant licensing basis following implementation of the proposed power uprate.

The licensee has not requested NRC review and approval of any changes to the GWMS licensing basis relative to EPU operation and consequently, this section of the evaluation does not constitute NRC approval of any changes that are being made to the GWMS in this regard.

Conclusion

The NRC staff has reviewed the licensee’s assessment of the effects of the proposed EPU on the capability of the GWMS to perform its specified functions and finds that the GWMS will continue to adequately process gaseous radioactive waste and preclude the possibility of waste gas explosions in accordance with the plant licensing basis. Therefore, the proposed EPU is considered to be acceptable with respect to the GWMS.

2.5.6.2 Liquid Waste Management Systems

Regulatory Evaluation

The liquid waste management system (LWMS) consists of process equipment and instrumentation necessary to collect, process, monitor and recycle/dispose of liquid radioactive waste. Major components in the system include the waste disposal evaporator, distillate demineralizers, transfer pumps and various waste system tanks used for collecting, holdup, and processing of the waste streams. As noted in Ginna UFSAR Section 3.1, a preliminary version of the criteria specified by 10 CFR Part 50, Appendix A, “General Design Criteria,” were used during NRC review of the Ginna licensing request. The adequacy of the Ginna plant design was later reviewed under the Systematic Evaluation Program based on the criteria that had been established and used for the review of newer reactor plant designs. Consequently, the Ginna licensing basis includes conformance with the GDC as discussed in UFSAR Sections 3.1.1 and 3.1.2. The NRC staff’s review of the LWMS focuses on the effects that the proposed EPU may have on previous analyses and considerations related to the processing and management of liquid radioactive waste. The acceptance criteria for the LWMS that are most applicable to the staff’s review of proposed power uprates are based on (1) 10 CFR 20.1302, insofar as it places specific limitations on the annual average concentrations of radioactive materials released at the boundary of the unrestricted area; (2) 10 CFR Part 50, Appendix A, GDC 60, “Control of Releases of Radioactive Materials,” insofar as it specifies that the plant design include means to control the release of radioactive effluents; (3) 10 CFR Part 50, Appendix A, GDC 61, “Fuel Storage and Handling and Radioactivity Control,” insofar as it specifies that systems that contain radioactivity be designed with suitable confinement, shielding, and filtration; (4) 10 CFR Part 50, Appendix I, Sections II.A and II.D, which set numerical guides for meeting the "as low as is reasonably achievable" criterion; and (5) other licensing-basis considerations that apply. The staff’s review of the LWMS is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5. Acceptability is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Section 11.2 of the Ginna UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

Technical Evaluation

The licensee's evaluation of the impact that EPU will have on the LWMS is provided in Section 2.5.6.2 of the licensing report. The licensee determined that the proposed power uprate will not significantly increase the amount of liquid that is normally processed by the LWMS, require any changes in the operation or design of the equipment used in the LWMS, radiological and environmental monitoring of the waste streams will not be affected, and no new or different radiological release paths will be introduced as a result of the proposed power uprate. The licensee also confirmed that the LWMS will remain capable of processing the increased radioactive nuclide concentrations that will exist during EPU operation. Since the design and operation of the LWMS will not change, the increased nuclide concentrations will not exceed the capability of the LWMS to process waste, and the volume of fluid flowing into the liquid radwaste system will not increase significantly as a result of EPU, the licensee concluded that the capability of the LWMS will continue to be adequate.

Based upon a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the LWMS to perform its specified functions. Because the amount of liquid radioactive waste will not exceed the design capacity of the LWMS and the capability to monitor effluents will not be affected, the staff agrees that the LWMS will continue to satisfy the plant licensing basis following implementation of the proposed power uprate.

The licensee has not requested NRC review and approval of any changes to the LWMS licensing basis relative to EPU operation and this evaluation does not constitute NRC approval of any changes that are being made to the licensing basis in this regard.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the capability of the LWMS to perform its specified functions and finds that the LWMS will continue to adequately process liquid radioactive waste in accordance with the plant licensing basis. Therefore, the proposed EPU is considered to be acceptable with respect to the LWMS.

2.5.6.3 Solid Waste Management Systems

Solid radioactive waste consists of wet and dry waste. Wet waste consists mostly of low specific activity spent secondary and primary resins and filters, and oil and sludge from various contaminated systems. The NRC staff's review relates primarily to the wet waste dewatering and liquid collection processes, and focuses on the impact that the proposed power uprate will have on the release of radioactive material to the environment via gaseous and liquid effluents. Because this is a subset of the evaluations performed in Sections 2.5.6.1 and 2.5.6.2, a separate evaluation of solid waste management systems is not required.

2.5.7 Additional Considerations

2.5.7.1 Emergency Diesel Engine Fuel Oil Storage and Transfer System

Nuclear power plants are required to have redundant onsite emergency power supplies of sufficient capacity to perform their safety functions (e.g., diesel engine-driven generator sets). The NRC staff's review focuses on increases in emergency diesel generator (EDG) electrical demand and the resulting increase in the amount of fuel oil necessary for the system to perform its safety function. Because the EDG fuel oil storage requirements for Ginna are based upon the amount of fuel oil that is consumed by the EDGs when they are operating at their fully loaded design rating, and the EDG electrical loads for EPU operation will not exceed the EDG full load rating, the fuel oil storage requirements for Ginna are not affected by the proposed power uprate. Therefore, an evaluation of the EDG fuel oil storage requirements is not required.

2.5.7.2 Light Load Handling System (Related to Refueling)

The light load handling system (LLHS) includes components and equipment used for handling new fuel at the receiving station and for loading spent fuel into shipping casks. The weight of the post-EPU fuel is bounded by current analysis. The post-EPU fuel has a shorter standard top nozzle than previously used at Ginna which will require changes to be made to the fuel handling tools and devices that are currently being used. The new spent fuel handling tools will be materially and structurally similar to the existing tools and will be capable of being used for handling both the current and post-EPU fuel types. Because the changes in the design of the fuel handling tools will not affect the capability of the LLHS to perform its specified functions, an evaluation of the LLHS for the proposed power uprate is not required.

2.5.8 Fire Protection

Regulatory Evaluation

The purpose of the fire protection program (FPP) is to provide assurance, through a defense-in-depth design, that a fire will not prevent the performance of necessary safe plant shutdown functions and will not significantly increase the risk of radioactive releases to the environment. The NRC staff's review focused on the effects of the increased decay heat on the plant's safe-shutdown analysis to ensure that structures, systems, and components (SSCs) required for the safe-shutdown of the plant are protected from the effects of the fire and will continue to be able to achieve and maintain safe-shutdown following a fire. The NRC's acceptance criteria for the FPP are based on: (1) 10 CFR 50.48 and associated Appendix R to 10 CFR Part 50, insofar as they require the development of an FPP to ensure, among other things, the capability to safely shutdown the plant; (2) GDC 3, insofar as it requires that (a) SSCs important to safety be designed and located to minimize the probability and effect of fires, (b) noncombustible and heat resistant materials be used, and (c) fire detection and fighting systems be provided and designed to minimize the adverse effects of fires on SSCs important to safety; and (3) GDC 5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions. Specific review criteria are contained in SRP Section 9.5.1, as supplemented by the guidance provided in Attachment 2 to Matrix 5 of Section 2.1 of RS-001.

Technical Evaluation

In RS-001, Attachment 2 to Matrix 5, "Supplemental Fire Protection Review Criteria," states that:

> . . . power uprates typically result in increases in decay heat generation following plant trips. These increases in decay heat usually do not affect the elements of a fire protection program related to (1) administrative controls, (2) fire suppression and detection systems, (3) fire barriers, (4) fire protection responsibilities of plant personnel, and (5) procedures and resources necessary for the repair of systems required to achieve and maintain cold shutdown. In addition, an increase in decay heat will usually not result in an increase in the potential for a radiological release resulting from a fire . . . where licensees rely on less than full capability systems for fire events . . . the licensee should provide specific analyses for fire events that demonstrate that (1) fuel integrity is maintained by demonstrating that the fuel design limits are not exceeded and (2) there are no adverse consequences on the reactor pressure vessel integrity or the attached piping. Plants that rely on alternative/dedicated or backup shutdown capability for post-fire safe-shutdown should analyze the impact of the power uprate on the alternative/dedicated or backup shutdown capability . . . The licensee should identify the impact of the power uprate on the plant's post-fire safe-shutdown procedures.

Sections 2.5.1.4, “Fire Protection,” and 2.13.1.2.1.3.2, “Fire,” of the licensing report satisfactorily address these fire protection requirements of the RS-001, Revision 0. The results of the Appendix R evaluation provided in Sections 2.5.1.4 and 2.13.1.2.1.3.2 of Attachment 5 demonstrate that the plant can be brought to a cold-shutdown condition using only safety-grade equipment following a fire, safe-shutdown earthquake, loss of offsite power, and the most limiting single failure.

The information provided in these sections, as supplemented by the licensee's letters dated December 6, 2005, and January 25, 2006, in response to the staff's request for additional information, satisfactorily demonstrates the licensee's compliance with the requirements in 10 CFR 50.48 and the review criteria in SRP 9.5.1 and RS-001. The licensee has indicated that the compliance with the fire protection and post-fire safe-shutdown program will not be affected because the EPU evaluation did not identify changes to design or operating conditions that will adversely impact the post-fire safe-shutdown capability. EPU evaluation does not change the credited equipment necessary for post-fire safe-shutdown, nor does it reroute essential cables or relocate essential components/equipment credited for post-fire safe-shutdown. The licensee has made no significant changes to the plant configuration or combustible loading as a result of modifications necessary to implement the EPU. Any minor changes will also be evaluated by the licensee under the plant's existing NRC approved FPP. However, additional equipment is added to the list of safe-shutdown components to account for the effects of increased decay heat.

Conclusion

The NRC staff has reviewed the licensee's fire-related safe-shutdown assessment and concludes that the licensee has adequately accounted for the effects of the increased decay heat on the ability of the required systems to achieve and maintain safe-shutdown conditions. The NRC staff further concludes that the FPP will continue to meet the requirements of 10 CFR 50.48, Appendix R to 10 CFR Part 50, and GDCs 3 and 5 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to fire protection.

2.6 Containment Review Considerations

2.6.1 Primary Containment Functional Design

Regulatory Evaluation

The containment encloses the reactor system and is the final barrier against the release of significant amounts of radioactive fission products in the event of an accident. The containment structure must be capable of withstanding, without loss of function, the pressure and temperature conditions resulting from postulated LOCAs, steam line accidents, or feedwater line accidents. The containment structure must continue to serve as a low leakage barrier against the release of fission products for as long as the postulated accident requires.

The NRC staff's review covers the pressure and temperature conditions in the containment due to a spectrum of postulated LOCAs and secondary line breaks. The NRC's acceptance criteria for primary containment functional design are based on GDC 16 and 50 for the containment and its associated systems being able to accommodate, without exceeding the design leakage rate and with sufficient margin, the calculated pressure and temperature conditions resulting from any LOCA; (2) GDC 38 for the containment heat removal system(s) function to rapidly reduce the containment pressure and temperature following any LOCA and maintain them at acceptably low levels; (3) GDC 13 for instrumentation to monitor variables and systems over their anticipated ranges for normal operation and for accident conditions; and (4) GDC 64 for monitoring reactor containment atmosphere for radioactivity that may be released from normal operations and postulated accidents. Specific review criteria are contained in SRP Section 6.2.1.1.A.

Technical Evaluation

a. Introduction

The Ginna containment is described in Section 6.2.1 of the UFSAR as:

> ... a reinforced concrete vertical right cylinder with a flat base and a hemispherical dome. A welded steel liner is attached to the inside face of the concrete shell to ensure a high degree of leak tightness.

The Ginna containment design pressure is 60 psig and the design temperature is 286 EF.

The LOCA is mitigated with the ECCS and the containment heat removal system. The ECCS consists of the passive accumulators, high-head SI pumps and the RHR pumps, which act as low head SI pumps. During the injection phase, the ECCS pumps take suction from the RWST. During the recirculation phase, the RHR pumps take suction from the containment sump. If high-head injection is needed during the recirculation phase, the high-head injection pumps take suction from the discharge of the RHR pumps. Heat is rejected from the RHR system to the component cooling water (CCW) system through the RHR heat exchanger and from the CCW system to the service water system through the CCW heat exchanger.

Heat removal from the containment atmosphere during a postulated accident is accomplished by the containment recirculation fan cooler (CRFC) system and the CS system. The CRFC system consists of four CRFC units (two per train). The CS system consists of two redundant pumps and two spray spargers. During the injection phase of a LOCA, the spray pumps take suction from the RWST. During the recirculation phase of the LOCA, the CS pumps, if needed, would take suction from the RHR pumps. The licensee does not credit CS cooling during the recirculation phase since there are no analyzed accidents that demonstrate a repressurization of containment in the sump recirculation phase.

b. LOCA

The licensee evaluated the design-basis LOCA relative to the containment peak pressure and temperature response at EPU conditions.

The containment analysis consists of two parts. First the mass and energy release from a high energy line break are calculated. The mass and energy release resulting from a LOCA are discussed in Section 2.6.3 of this SE.

The second part of the containment analysis consists of calculating the containment conditions resulting from this release of mass and energy into the containment.

The licensee used the GOTHIC (Generation of Thermal Hydraulic Information for Containments) 7.2 computer code (Reference 2) to calculate the pressure and temperature conditions within the containment resulting from a postulated high energy line break. GOTHIC is a general purpose computer program for the prediction of the thermal hydraulic conditions in nuclear power plant containments. GOTHIC solves the conservation equations for mass, momentum and energy for multi-component, multi-phase flow.

GOTHIC is developed for EPRI by Numerical Applications, Incorporated. GOTHIC undergoes an extensive verification and benchmarking process against both analytic solutions and special effects and integral heat transfer and containment data. It is subject to 10 CFR Part 50, Appendix B and 10 CFR Part 21 requirements.

In its licensing report, the licensee stated that the GOTHIC containment modeling for Ginna is consistent with an NRC-approved Kewaunee evaluation model (Reference 3). The Kewaunee analyses used GOTHIC 7.0. The Ginna analyses use GOTHIC 7.2. GOTHIC 7.2 is consistent with the NRC staff’s approval of the use of GOTHIC in the Kewaunee SER. GOTHIC 7.2 also contains user-controlled enhancements. The licensee stated that none of these enhancements were used for the Ginna calculations.

The licensee stated that the Ginna model thermal-hydraulic response was benchmarked against the double ended suction break case presented in the Ginna UFSAR, Section 6.2. The results show that the GOTHIC 7.2 model agrees with the UFSAR results. GOTHIC predicts slightly higher peak pressure and gas temperature. The licensee attributes this, not to a difference in computer codes, but to a difference in modeling. The GOTHIC model accounts for paint layers and (air) gaps between materials which add thermal resistance.

Since the licensee followed the NRC staff’s guidance on the use of GOTHIC, the staff finds the licensee’s use of GOTHIC for LOCA and main steam line break accident (MSLB) analyses to be acceptable.

The licensee assumed initial containment conditions which result in conservative calculations. The initial pressure is assumed to be 1 psig. The initial relative humidity is low (20%). These conditions result in more air mass in containment which produce a higher accident pressure. A relatively high initial air temperature results in a higher pressure (for the same air mass).

The licensee assumes a free containment volume of 1,000,000 ft^3 which is the UFSAR value and is, therefore, acceptable.

As mentioned above for the benchmark problem, the licensee models all exposed concrete and carbon steel surfaces as covered with an overcoat and primer. This increases thermal resistance. Gaps between insulation, steel and concrete also increase thermal resistance.

The licensee models the injection of nitrogen gas from the ECCS accumulators into the containment. This increases the containment accident pressure.

The licensee developed a sump recirculation model for the GOTHIC calculation, which couples the residual and component cooling water heat exchangers and service water piping. This model is described by the licensee in a December 6, 2005, letter. The model does not include recirculation spray since no credit is taken during recirculation for CS.

The licensee assumes two possible single failures: maximum and minimum safeguards SI flow. Both assume a loss of offsite power at the onset of the event which necessitates use of the EDGs. The minimum safeguards SI flow assumption is the loss of one train of safeguards equipment by the assumed single failure of an EDG. This leaves available two high-head SI pumps and one low head SI pump as well as one core spray pump and two containment recirculation fan cooler units. The maximum safeguards SI flow case assumes full SI flow but a single failure of one train of CS. These single failure assumptions are typically assumed for Westinghouse-designed PWRs and the NRC staff has previously found these assumptions to be acceptably limiting since the minimum case minimizes core cooling and the maximum case results in faster core reflood which results in a faster release of heat to the containment as well as minimizing containment cooling by crediting only one train of CS.

In the case of either the minimum SI flow single failure or the maximum SI flow single failure, one train of CS is unavailable. For the maximum SI flow case, both trains of CRFCs are available. For the minimum SI flow single failure case, only one train (two CRFC units) is available.

The CS is credited only during the injection phase of the LOCA. Spray initiates on a coincidence of two sets of two-out-of-three high-high containment pressure signal. The licensee has changed the high-high setpoint for the EPU. The spray takes suction from the RWST. The RWST water is assumed to be at 104 EF. This is the maximum auxiliary building temperature listed in the Ginna UFSAR and is therefore conservative and acceptable. The initial spray drop size is assumed to be 1000 microns which is consistent with the UFSAR and is therefore acceptable. GOTHIC models the heat and mass transfer to the drop as it falls through the containment atmosphere. Any unevaporated spray water is added to the sump. Comparisons of the GOTHIC drop evaporation model with data show acceptable agreement (Reference 3).

The major heat exchangers used in the Ginna containment analysis to model heat removal from the containment are the containment recirculation fan coolers (CRFCs), the RHR heat exchangers and the CCW heat exchagers. The CS system does not contain heat exchangers. The RHR and CCW heat exchangers are modeled with GOTHIC heat exchanger components. The licensee states that the performance of these heat exchanger models was benchmarked against design conditions and low flow conditions from the heat exchanger specifications data to ensure that the models adequately predict heat removal. This is acceptable.

The CRFCs are cooled by the service water system and are, therefore, included in the licensee's Service Water System Reliability Optimization Program (SWSROP). This program complies with the guidance of NRC Generic Letter 89-13 (Reference 4) to ensure proper cooling of important components cooled by service water. The licensee's December 6, 2005, letter describes the actions which are performed as part of this program. They include periodic cleaning, pressure drop testing, weekly monitoring of CRFC flow rates and quarterly testing of air flow rates.

The licensee states that the containment recirculation fan cooler heat removal rate is modeled as a function of the containment saturation temperature, water inlet temperature, air flow rate and water flow rate based on a method used by the containment recirculation fan cooler manufacturer. The licensee states that:

> The manufacturer's methodology was verified by comparing its results to actual test results from steam/air mixture testing at approximately 60 psig and 286 EF [containment design pressure and temperature conditions]. The comparison of the test results for actual cooler heat transfer rates with the manufacturer's heat transfer results underestimated the test results by approximately 20%.

This is conservative and therefore acceptable.

The ECCS accumulators contain nitrogen as a cover gas over the water surface. Upon discharge of the accumulator water into the reactor, the nitrogen gas is assumed to be released to the containment where it contributes to the total containment pressure. The licensee models the nitrogen release as a GOTHIC boundary condition. The details of the nitrogen release model are described in the licensee's December 6, 2005, letter. The NRC staff has reviewed the licensee's description of the model and finds it a reasonable representation of the physical process and therefore acceptable.

The licensee determined that the peak pressure as a result of a LOCA occurs as a result of the double-ended hot leg break. The calculated peak containment pressure is 54.2 psig. The containment design pressure is 60 psig.

The peak temperature of the containment atmosphere as a result of a LOCA occurs for the double-ended pump suction break with minimum safeguards. The calculated value is 282.4 EF. The containment temperature acceptance limit is 286 EF.

The peak containment pressure at 24 hours following start of the LOCA is 7.77 psig. This is significantly less than half the peak containment pressure. It is therefore acceptable, following the guidance of SRP Section 6.2.1.1.A to assume that the containment leakage rate after 24 hours is less than half the TS containment leakage rate limit of L_a.

c. Main Steam Line Break (MSLB)

The licensee performed analyses of the containment response to the MSLB analysis in support of a license amendment request related to the modification of manual isolation valves in the Ginna feedwater lines. These manual valves will be converted to fast-closing (Reference 73). The postulated MSLB accident containment analysis is described in an April 29, 2005, licensee letter to the NRC.

The major input assumptions for the containment analysis are listed in Tables 1 through 3 of the April 29, 2005, letter. The major input assumptions for the secondary side systems are presented in Section 4.2 of that letter describing the containment response analysis. Reactor coolant system assumptions are presented in Section 4.3. As described in the SE for Amendment No. 95, dated March 16, 2006, the NRC staff found the licensee's proposal to install fast acting MFIVs (Reference 73) and the accompanying MSLB accident analysis for containment to be acceptable.

The licensee's MSLB containment analyses to support the installation of the fast-acting (Reference 73) assumed extended power uprate conditions. Therefore, the licensee's request for EPU is acceptable with respect to the MSLB accident containment analyses.

Conclusion

The NRC staff has reviewed the licensee's assessment of the containment pressure and temperature transient and concludes that the licensee has adequately accounted for the increase of mass and energy that would result from the proposed EPU. The NRC staff further concludes that containment systems will continue to provide sufficient pressure and temperature mitigation capability to ensure that containment integrity is maintained. The NRC staff also concludes that the containment systems and instrumentation will continue to be adequate for monitoring containment parameters and release of radioactivity during normal and accident conditions and will continue to meet the requirements of GDCs 13, 16, 38, 50, and 64 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to containment functional design.

2.6.2 Subcompartment Analysis

Regulatory Evaluation

A subcompartment is defined as any fully or partially enclosed volume within the primary containment that houses high-energy piping and would limit the flow of fluid to the main containment volume in the event of a postulated pipe rupture within the volume. The NRC staff's review for subcompartment analyses covered the determination of the design differential pressure values for containment subcompartments. The NRC staff's review focused on the effects of the increase in mass and energy release into the containment due to operation at EPU conditions, and the resulting increase in pressurization. The NRC's acceptance criteria for subcompartment analyses are based on: (1) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, and that such SSCs be protected against dynamic effects, and (2) GDC 50, insofar as it requires that containment subcompartments be designed with sufficient margin to prevent fracture of the structure due to the calculated pressure differential conditions across the walls of the subcompartments. Specific review criteria are contained in SRP Section 6.2.1.2.

Technical Evaluation

The licensee classified the subcompartment analyses as short-term LOCA analyses since the pressure pulse of interest for these analyses is generally less than 3 seconds. These short- term LOCA analyses are performed for Ginna for the reactor coolant loop compartments (UFSAR Section 6.2.1.3.2), the concrete around and under the RV (UFSAR Section 6.2.1.3.4) and the concrete structures around the SGs (UFSAR Section 6.2.1.3.4).

The NRC has approved the application of leak-before-break methods to Ginna for the RCS loops (Reference 6), RHR branch lines (Reference 7) and the surge line and accumulator lines (Reference 8). Thus, only lines less than 10 inches in diameter are subject to instantaneous postulated breaks.

A break in a high energy line at EPU conditions results in a higher mass flux into the subcompartment because of the lower RCS temperature. This would increase the subcompartment pressure. However, the reduction in break size due to credit for leak-before-break offsets the effect of coolant temperature and the net result is a lower subcompartment pressure. The subcompartment loads are therefore bounded by the current licensing basis described in UFSAR.

Conclusion

The NRC staff has reviewed the subcompartment assessment performed by the licensee and the change in predicted pressurization resulting from the increased mass and energy release. The NRC staff concludes that containment SSCs important to safety will continue to be protected from the dynamic effects resulting from pipe breaks and that the subcompartments will continue to have sufficient margins to prevent fracture of the structure due to pressure difference across the walls following implementation of the proposed EPU. Based on this, the NRC staff concludes that the plant will continue to meet GDCs 4 and 50 for the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to subcompartment analyses.

2.6.3 Mass and Energy Release

2.6.3.1 Mass and Energy Release Analysis for Postulated Loss-of-Coolant Accident

Regulatory Evaluation

The release of high-energy fluid into containment from pipe breaks could challenge the structural integrity of the containment, including subcompartments and systems within the containment. The NRC staff's review covered the energy sources that are available for release to the containment and the mass and energy release rate calculations for the initial blowdown phase of the accident. The NRC's acceptance criteria for mass and energy release analyses for postulated LOCAs are based on: (1) GDC 50, insofar as it requires that sufficient conservatism be provided in the mass and energy release analysis to assure that containment design margin is maintained and (2) 10 CFR Part 50, Appendix K, insofar as it identifies sources of energy during a LOCA. Specific review criteria are contained in SRP Section 6.2.1.3.

Technical Evaluation

The long-term LOCA mass and energy releases were analyzed for Ginna to 3600 seconds (1 hour) using NRC-approved Westinghouse methods (Reference 9). At 1 hour, all the energy in the primary heat structures and SG secondary system is assumed released to the containment and the systems are depressurized to 14.7 psia and 212 EF. The analysis after 1 hour considers boil off from the core at decay heating rate. These calculations are done using the GOTHIC code.

The calculated LOCA mass and energy releases are input to the LOCA containment analyses discussed in Section 2.6.1 of this SE report input.

The core rated thermal power (RTP) assumed for these calculations is 1811 MWt. This is 102% of the extended power uprate thermal power of 1775 MWt. The 2% uncertainty accounts for possible instrument error in compliance with the guidelines of RG 1.49 (Reference 10). The licensee has also used American Nuclear Society (ANS) Standard 5.1 with a 2σ uncertainty band and other assumptions that maximize the decay heat added to the coolant.

Section 2.6.3.1.2.1.2 of licensing report described the assumptions and input used for the LOCA mass and energy release calculations. The NRC staff has reviewed the input and assumptions and agrees that they are sufficiently conservative. For example, in addition to the 2% uncertainty on RTP, the licensee has bounded the RCS operating temperature and pressure. This maximizes the mass and energy release. The core stored energy is maximized by assuming the time in fuel life of maximum densification. The RCS volume is increased by 3% to account for dimensional uncertainty and thermal expansion. This provides more mass to be released. No SG tube plugging is assumed. This also maximizes the RCS inventory as well as the SG tube heat transfer area. A critical flow rate correlation and assumptions which reduce flow resistance maximize the break flow rate. The staff therefore considers the input and assumptions for the mass and energy release to the containment to be acceptably conservative.

The licensee included the following sources of mass addition to the containment:

- RCS water
- accumulator water
- pumped injection

The licensee included the following sources of energy addition to the containment:

- RCS water
- accumulator water (both accumulators inject)
- pumped injection
- decay heat
- core stored energy
- RCS metal including SG tubes
- SG metal
- SG secondary energy
- feedwater into and steam out of SG secondary

The NRC staff considers these mass and energy sources to be acceptably complete.

The licensee stated that energy from the zirconium-water reaction was not included because the energy release from the fuel rod is maximized for this calculation. Therefore, the cladding does not reach the temperature at which the zirconium water reaction is significant. This is acceptable since it maximizes the fuel stored energy released to containment.

The single failure assumptions are discussed in Section 2.6.1 of this SE. They are acceptable, as discussed in that section.

There are no specific criteria for the mass and energy release calculation results. Acceptable calculated peak containment pressures and temperatures demonstrate acceptability of the mass and energy release calculations. For Ginna at EPU conditions, these results are acceptable as discussed in Section 2.6.1 of this SE.

Conclusion

The NRC staff has reviewed the licensee's mass and energy release assessment and concludes that the licensee has adequately addressed the effects of the proposed EPU and appropriately accounts for the sources of energy identified in 10 CFR Part 50, Appendix K. Based on this, the NRC staff finds that the mass and energy release analysis meets the requirements in GDC 50 for ensuring that the analysis is conservative. Therefore, the NRC staff finds the proposed EPU acceptable with respect to mass and energy release for postulated LOCA.

2.6.3.2 Mass and Energy Release Analysis for Secondary System Pipe Ruptures

Regulatory Evaluation

The NRC staff's review covered the energy sources that are available for release to the containment, the mass and energy release rate calculations, and the single-failure analyses performed for steam and feedwater line isolation provisions, which would limit the flow of steam or feedwater to the assumed pipe rupture. The NRC's acceptance criteria for mass and energy release analysis for secondary system pipe ruptures are based on GDC 50, insofar as it requires that the margin in the design of the containment structure reflect consideration of the effects of potential energy sources that have not been included in the determination of peak conditions, the experience and experimental data available for defining accident phenomena and containment response, and the conservatism of the model and the values of input parameters. Specific review criteria are contained in SRP Section 6.2.1.4.

Technical Evaluation

The licensee performed analyses of the containment response to the MSLB analysis in support of a license amendment request related to the modification of manual isolation valves in the Ginna feedwater lines. These manual valves will be converted to fast-closing (Reference 73). The postulated MSLB accident containment analysis, including secondary mass and energy release calculations, is described in an April 29, 2005, letter to the NRC (Reference 8).

The major input assumptions for the containment analysis are listed in Tables 1 through 3 of the April 29, 2005, letter. The major input assumptions for the secondary side systems are presented in Section 4.2 of the containment response analysis. The RCS assumptions are presented in Section 4.3 of the containment response analysis.

The NRC staff found the licensee's proposal to install fast acting MFIVs (Reference 73) and the accompanying MSLB accident analysis for containment to be acceptable as described in its SE supporting Amendment No. 95, dated March 16, 2006. The licensee's MSLB containment analyses to support the installation of the fast-acting MFIVs (Reference 73) assumed extended power uprate conditions. Therefore, the licensee's request for extended power uprate is acceptable with respect to the MSLB accident mass and energy release analyses.

Conclusion

The NRC staff has reviewed the mass and energy release assessment performed by the licensee for postulated secondary system pipe ruptures and finds that the licensee has adequately addressed the effects of the proposed EPU. Based on this, the NRC staff concludes that the analysis meets the requirements in GDC 50 for ensuring that the analysis is conservative (i.e., that the analysis includes sufficient margin). Therefore, the NRC staff finds the proposed EPU acceptable with respect to mass and energy release for postulated secondary system pipe ruptures.

2.6.4 Combustible Gas Control in Containment

Regulatory Evaluation

Following a LOCA, hydrogen and oxygen may accumulate inside the containment due to chemical reactions between the fuel rod cladding and steam, corrosion of aluminum and other materials, and radiolytic decomposition of water. If excessive hydrogen is generated, it may form a combustible mixture in the containment atmosphere. The NRC staff's review covered (1) the production and accumulation of combustible gases, (2) the capability to prevent high concentrations of combustible gases in local areas, (3) the capability to monitor combustible gas concentrations, and (4) the capability to reduce combustible gas concentrations. The NRC staff's review primarily focused on any impact that the proposed EPU may have on hydrogen release assumptions, and how increases in hydrogen release are mitigated. The NRC's acceptance criteria for combustible gas control in containment are based on (1) 10 CFR 50.44, insofar as it requires that plants be provided with the capability for controlling combustible gas concentrations in the containment atmosphere; (2) GDC 5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions; (3) GDC 41, insofar as it requires that systems be provided to control the concentration of hydrogen or oxygen that may be released into the reactor containment following postulated accidents to ensure that containment integrity is maintained; (4) GDC 42, insofar as it requires that systems required by GDC 41 be designed to permit appropriate periodic inspection; and (5) GDC 43, insofar as it requires that systems required by GDC 41 be designed to permit appropriate periodic testing. Specific review criteria are contained in SRP Section 6.2.5.

Technical Evaluation

Ginna has dual hydrogen recombiners, which are designed to limit hydrogen concentrations in containment following a LOCA.

On September 16, 2003, the NRC revised 10 CFR 50.44, "Standards for combustible gas control system in light-water-cooled power reactors." Requirements for hydrogen recombiners and hydrogen purge systems were eliminated and requirements on the hydrogen and oxygen monitoring systems were relaxed.

The licensee adopted the provisions of the revised rule by proposing changes to TSs 3.3.3 and 3.6.7 in an August 6, 2004, letter (Reference 11), which was later supplemented on March 4, 2005 (Reference 12). The amendment request was in accordance with the NRC-approved TS Task Force (TSTF) Change TSTF-447, Revision 1. The NRC approved the requested changes to the Ginna TSs (Reference 13).

In the licensing report, the licensee stated that:

> Based on the NRC-approved changes and the low safety significance of post-LOCA combustible gas generation in large, dry pressurized water reactor containment buildings, such as Ginna Station, the existing UFSAR information will be classified as historical and thus not updated for EPU purposes. However, the capability to monitor post-accident hydrogen concentration in containment is retained, consistent with the requirement of 10 CFR 50.44(b)(4)(ii), but the components necessary to monitor hydrogen no longer need to be classified as safety related as previously recommended by Regulatory Guide 1.97.

The NRC staff finds this acceptable and consistent with the intent of revision to 10 CFR 50.44.

Conclusion

The NRC staff has reviewed the licensee's assessment related to combustible gas and concludes that the plant will continue to have sufficient capabilities, consistent with the requirements in 10 CFR 50.44, 10 CFR 50.46, and GDCs 5, 41, 42, and 43 as discussed above. Therefore, the NRC staff finds the proposed EPU acceptable with respect to combustible gas control in containment.

2.6.5 Containment Heat Removal

Regulatory Evaluation

Fan cooler systems, spray systems, and RHR systems are provided to remove heat from the containment atmosphere and from the water in the containment sump. The NRC staff's review in this area focused on (1) the effects of the proposed EPU on the analyses of the available net positive suction head (NPSH) to the containment heat removal system pumps and (2) the analyses of the heat removal capabilities of the spray water system and the fan cooler heat exchangers. The NRC's acceptance criteria for containment heat removal are based on GDC 38, insofar as it requires that the containment heat removal system be capable of rapidly reducing the containment pressure and temperature following a LOCA, and maintaining them at acceptably low levels. Specific review criteria are contained in SRP Section 6.2.2 as supplemented by Draft Guide (DG) 1107.

Technical Evaluation

The licensee's response to NRC Generic Letter 97-04 (Reference 14) described the ECCS and CS pump suction arrangement:

> During the injection phase post-accident, the emergency core cooling system (ECCS) pumps take suction from the refueling water storage tank (RWST). Following postulated loss-of-cooling accidents (LOCA), once the RWST has been depleted to a specified level, actions are initiated to transfer the suctions of the RHR pumps to containment sump "B." The only pumps at Ginna that take suction directly from sump "B" are the RHR pumps. Each RHR pump discharges through a heat exchanger and control valves, and injects to the RV upper plenum via separate headers, through core deluge valves. The other ECCS pumps are high head safety injection pumps (SI) and containment spray (Spray) pumps. The SI and Spay pumps have the ability to take suction from the RHR pumps' discharge piping. Operators direct valve re-alignment to the sump recirculation phase by emergency procedures.

In a letter dated March 3, 2006, in response to an NRC question, the licensee described the Ginna licensing basis with respect to NPSH as follows:

> The licensing basis for the Ginna EPU ECCS and containment spray pump NPSH calculations has been updated since the Ginna response to GL 97-04. Ginna is in the process of implementing a change in the manner in which the RHR discharge throttle valves are operated in the ECCS system. The valves will be permanently throttled to avoid the need for operator action to position the valves post-LOCA. A revised analysis has been completed to support this new throttle position. This change has been made to address an identified concern related to reducing operator dose post-LOCA. The UFSAR will be updated to reference the new analysis.
>
> These activities are not affected by EPU. The analyses for EPU assumed a reduced level of ECCS flow, which provided adequate core cooling during the injection phase while

reducing the required NPSH during the recirculation phase, as compared to the pre-EPU analysis.

The licensee, consistent with the guidance of SRP Section 6.2.2, assumes the sump “B” water temperature and the containment atmosphere are saturated. This results in the available NPSH being independent of the sump temperature and therefore independent of the initial reactor power level.

Containment heat removal is included in the containment analyses evaluated in Section 2.6.1 of this SE. Included in that discussion is the staff’s evaluation of the licensee’s single failure assumptions for the CRFCs and the CS systems. As noted in Section 2.6.3 of this SE, the licensee uses the ANS 5.1 decay heat model with a 2σ uncertainty band included. This is conservative and acceptable.

Conclusion

The NRC staff has reviewed the containment heat removal systems assessment provided by the licensee and concludes that the licensee has adequately addressed the effects of the proposed EPU. The NRC staff finds that the systems will continue to meet GDC 38 for rapidly reducing the containment pressure and temperature following a LOCA, and maintaining them at acceptably low levels. Therefore, the NRC staff finds the proposed EPU acceptable with respect to containment heat removal systems.

2.6.6 Secondary Containment Functional Design

Ginna does not have a secondary containment.

2.6.7 Additional Review Areas

2.6.7.1 Generic Letter (GL) 96-06

Regulatory Evaluation

GL 96-06 (Reference 15) addressed the issue of overpressurization of containment piping penetrations due to thermal expansion of fluid between closed isolation valves.

GDC 50 requires that the reactor containment structure, including access openings, penetrations, and the containment heat removal system shall be designed so that the containment structure and its internal compartments can accommodate, without exceeding the design leakage rate and with sufficient margin, the calculated pressure and temperature from any LOCA.

Technical Evaluation

An EPU has the potential for affecting the licensee’s response to GL 96-06.

The NRC documented the results of its review of the licensee’s response to GL 96-06 in an October 6, 2003, letter (Reference 16). The NRC agreed to the licensee’s permanent solution of installing relief valves on penetrations susceptible to thermal overpresurization by January 3, 1997. The NRC letter noted that these modifications were completed.

In its February 16, 2006 (Reference 17), letter, the licensee stated that these relief valves will function acceptably, as needed, at EPU conditions for the following reasons:

- No new potentially water solid piping sections in containment are created by the EPU.
- The original Ginna evaluation of overpressurization potential was conservatively based on a temperature rise to the Ginna design basis containment temperature of 286 EF over a ten second period (Thermal inertia of the penetration and contained water were conservatively ignored).
- The relief valves installed on containment penetrations as a result of GL 96-06 have a relief capacity of more than two times the required volumetric expansion rate of the most limiting penetration.
- The margin in relief valve volumetric capacity and the use of the containment design temperature of 286 EF ensure that the existing thermal relief valves are adequately sized to accommodate the change in containment transient temperature due to EPU operating conditions.

The NRC staff finds that the licensee's evaluation of containment temperature response and relief valve capacity are adequate to ensure that penetrations susceptible to thermal overpressurization will continue to accommodate the effects of a LOCA following the EPU.

Conclusion

The NRC staff has reviewed the licensee's compliance with the recommendations of GL 96-06 with respect to the EPU. The licensee has demonstrated that, in accordance with GDC 50, the containment penetrations will not be overpressurized by an increase in containment temperature at EPU conditions as a result of a postulated design basis accident.

2.7 Habitability, Filtration, and Ventilation

2.7.1 Control Room Habitability System

Regulatory Evaluation

The NRC staff reviewed the control room habitability system and control building layout and structures to ensure that plant operators are adequately protected from the effects of accidental releases of toxic and radioactive gases. A further objective of the NRC staff's review was to ensure that the control room can be maintained as the backup center from which technical support center personnel can safely operate in the case of an accident. The NRC staff's review focused on the effects of the proposed EPU on radiation doses, toxic gas concentrations, and estimates of dispersion of airborne contamination. The NRC's acceptance criteria for the control room habitability system are based on (1) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with postulated accidents, including the effects of the release of toxic gases; and (2) GDC-19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent, to any part of the body, for the duration of the accident. Specific review criteria are contained in SRP Section 6.4 and other guidance provided in Matrix 7 of RS-001.

Technical Evaluation

The NRC staff reviewed information provided by the licensee in its submittal that documents its review of the Control Room Habitability System. The control room emergency zone (CREZ) and the control room emergency air treatment system (CREATS) are designed to protect the control room from the effects of external events including seismic, weather, toxic gas and smoke. Seismic and weather considerations remain unchanged for EPU. There are no new chemical or combustible materials stored near or on-site as a result of EPU. Radiological consequences to the control room are affected by EPU. The radiological impact has been shown by analysis to be acceptable and within the limits specified in GDC 19.

The licensee evaluated the impact of EPU on heat loads for ventilation systems in the Relay Room, Battery Rooms, and the control room HVAC room and determined that there was no impact. The licensee also determined that the control room can act to provide key TSC personnel with a backup location from which to perform their function if it were necessary. The licensee also reviewed the impact of EPU on Renewed Plant Operating License Evaluations and determined that there were no new aging effects that required management.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the effects of the proposed EPU on the ability of the control room habitability system to protect plant operators against the effects of accidental releases of toxic and radioactive gases. The NRC staff concludes that the licensee has adequately accounted for the increase of toxic and radioactive gases that would result from the proposed EPU. The NRC staff further concludes that the control room habitability system will continue to provide the required protection following implementation of the proposed EPU. Based on this, the NRC staff concludes that the control room habitability system will continue to meet the requirements of GDCs 4 and 19. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the control room habitability system.

2.7.2 Engineered Safety Feature (ESF) Atmosphere Cleanup

Regulatory Evaluation

ESF atmosphere cleanup systems are designed for fission product removal in post accident environments. These systems generally include primary systems (e.g., in-containment recirculation) and secondary systems (e.g., emergency or postaccident air-cleaning systems) for the fuel-handling building, control room, shield building, and areas containing ESF components. For each ESF atmosphere cleanup system, the NRC staff's review focused on the effects of the proposed EPU on system functional design, environmental design, and provisions to preclude temperatures in the adsorber section from exceeding design limits. The NRC's acceptance criteria for the ESF atmosphere cleanup systems are based on (1) GDC 19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent, to any part of the body, for the duration of the accident; (2) GDC 41, insofar as it requires that systems to control fission products released into the reactor containment be provided to reduce the concentration and quality of fission products released to the environment following postulated accidents; (3) GDC-61, insofar as it requires that systems that may contain radioactivity be designed to assure adequate safety under normal and postulated accident conditions; and (4) GDC-64, insofar as it requires that means shall be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences (AOOs), and postulated accidents. Specific review criteria are contained in SRP Section 6.5.1.

Technical Evaluation

The NRC staff reviewed information provided by the licensee in its submittal that documents its review of the ESF atmospheric cleanup systems. In conducting its review, the licensee considered each of the systems that provide atmospheric clean up.

The control room atmosphere is cleaned by the CREATS, which functions to recirculate and filter air in the control room emergency zone during accident conditions. Filter and operational test programs assure functionality. Impact of increased radiation source term due to EPU has been evaluated and found to be acceptable. There are no new toxic gas concerns as a result of EPU.

The containment atmosphere is cleaned by the containment spray system (CSS) which, with sodium hydroxide injection, scrubs the containment atmosphere and the containment recirculation fan cooler system (CRFC) which has both HEPA filters and carbon adsorbers. The carbon adsorbers are not credited in accident analyses. Appropriate test programs assure system functionality. The licensee considered heat generation in the carbon adsorber due to the increased EPU source term and determined that the decay heat produced by the collected fission products will not cause ignition of the charcoal or overheating to the point of desorption of the collected fission products.

The licensee evaluated decay heat generation in carbon adsorbers and dissipation by normal air flow and with a loss of air flow. The decay heat generation rate using the alternate source term and EPU was shown to be less than the previous decay heat rate based on the TID source term. Heat dissipation is not adversely impacted by the EPU.

The auxiliary building and spent fuel pool (SFP) atmosphere is cleaned by the SFP filter system. Credit for the system filters is taken in the Fuel Handling Accident Analysis. Appropriate testing for filter performance and functionality is required.

The licensee also reviewed the impact of EPU on Renewed Plant Operating License Evaluations and determined that there were no new aging effects for the ESF atmospheric cleanup systems that required management.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ESF atmosphere cleanup systems. The NRC staff concludes that the licensee has adequately accounted for the increase of fission products and changes in expected environmental conditions that would result from the proposed EPU, and the NRC staff further concludes that the ESF atmosphere cleanup systems will continue to provide adequate fission product removal in postaccident environments following implementation of the proposed EPU. Based on this, the NRC staff concludes that the ESF atmosphere cleanup systems will continue to meet the requirements of GDCs 19, 41, 61, and 64. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the ESF atmosphere cleanup systems.

2.7.3 Ventilation Systems

2.7.3.1 Control Room Area Ventilation System

Regulatory Evaluation

The function of the control room area ventilation system (CRAVS) is to provide a controlled environment for the comfort and safety of control room personnel and to support the operability of control room components during normal operation, AOOs, and DBA conditions. The NRC's review of the CRAVS focused on the effects that the proposed EPU will have on the functional performance of safety-related portions of the system. The review included the effects of radiation, combustion, and other toxic products; and the expected environmental conditions in areas served by the CRAVS. The NRC's acceptance criteria for the CRAVS are based on (1) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (2) GDC 19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident; and (3) GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents. Specific review criteria are contained in SRP Section 9.4.1.

Technical Evaluation

The staff reviewed information provided by the licensee in its submittal that documents its review of the CRAVS, which is the control room HVAC system (CRHVAC) and consists of two systems: (1) the normal ventilation system, and (2) the CREATS. In conducting its review, the licensee considered each of the systems that provide control of the control room environment during normal and accident conditions.

The normal HVAC system provides the control room with fresh outside air, exhaust, coarse filtration, and temperature control to provide the operators with a safe and comfortable working environment. In the Purge mode of operation, this system provides the maximum amount of fresh air to purge airborne contaminants from the control room emergency zone (CREZ). The normal HVAC system's outside air intake duct is equipped with redundant trains of radiation, chlorine, and ammonia monitors, any of which will actuate the emergency mode of operation and provide an alarm in the control room. The normal HVAC system is also equipped with a smoke detector, upstream of the normal return air fan, to monitor the return airflow from the CREZ and to provide an alarm in the control room.

The CREATS is normally in standby and is configured to provide zone isolation, re-circulation, and filtration under accident conditions. The system isolates the normal HVAC system from the CREZ and recirculates the CREZ air through HEPA and charcoal filter banks, but is not designed to pressurize the CREZ. It is designed to satisfy GDC 19, "Control room" and the 30-day dose acceptance criteria of 5 rem TEDE, provided in 10 CFR 50.67. The CREATS is also designed to protect the operators from exposure to smoke and toxic gas. Detailed licensee analyses show that the CREZ can meet the GDC requirements for the increased EPU source term. The toxic gas and smoke requirements are unchanged by EPU.

The NRC staff finds that the licensee's methodology and assumptions were adequate and that the results continue to ensure that the plant operators will be adequately protected.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ability of the CRAVS to provide a controlled environment for the comfort and safety of control room personnel and to support the operability of control room components. The NRC staff concludes that the licensee has adequately accounted for the increase of toxic and radioactive gases that would result from a DBA under the conditions of the proposed EPU, and associated changes to parameters affecting environmental conditions for control room personnel and equipment. Accordingly, the NRC staff concludes that the CRAVS will continue to provide an acceptable control room environment for safe operation of the plant following implementation of the proposed EPU. The NRC staff also concludes that the system will continue to suitably control the release of gaseous radioactive effluents to the environment. Based on this, the NRC staff concludes that the CRAVS will continue to meet the requirements of GDC 4, 19, and 60. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the CRAVS.

2.7.4 Spent Fuel Pool Area Ventilation System

Regulatory Evaluation

The function of the spent fuel pool area ventilation system (SFPAVS) is to maintain ventilation in the spent fuel pool equipment areas, permit personnel access, and control airborne radioactivity in the area during normal operation, AOOs, and following postulated fuel handling accidents. The NRC staff's review focused on the effects of the proposed EPU on the functional performance of the safety-related portions of the system. The NRC's acceptance criteria for the SFPAVS are based on (1) GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents, and (2) GDC 61, insofar as it requires that systems which contain radioactivity be designed with appropriate confinement and containment. Specific review criteria are contained in SRP Section 9.4.2.

Technical Evaluation

The NRC staff reviewed information provided by the licensee in its submittal that documents its review of the SFPAVS. In conducting its review, the licensee considered the functions and operation of the system and the impact of the proposed EPU.

The SFPAVS is part of the auxiliary building ventilation system. The SFPAVS serves to control airborne radioactivity in the spent fuel pool area during normal operating conditions. This is accomplished by directing air from the auxiliary building supply air unit across both the spent fuel pool and the decontamination pit to exhaust air ducts, which are connected to the suction of the auxiliary building exhaust fan C. Exhaust air from the spent fuel pool water surface is drawn through roughing filters and, depending on system alignment, charcoal filters. Discharge from the auxiliary building exhaust fan C passes through HEPA filters, a main auxiliary building exhaust fan, and then out the plant vent. During handling of recently irradiated fuel in the auxiliary building, plant technical specifications require that the spent fuel pool charcoal adsorber system, including its associated fans, be in operation.

The SFPAVS was evaluated to ensure it is capable of performing its intended functions at EPU conditions. The decay heat loads in the spent fuel pool increase due to the EPU conditions. EPU decay heat loads and pool water temperatures have been evaluated to ensure that the system is capable of performing its intended functions under normal EPU and refueling modes. The activities that occur in the decontamination pit are unaffected by EPU, therefore there are no impacts of that portion of the ventilation system due to EPU. Section 2.9.2 of this SE discusses the acceptable performance during a postulation fuel-handling accident.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the SFPAVS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system's capability to maintain ventilation in the spent fuel pool equipment areas, permit personnel access, control airborne radioactivity in the area, control release of gaseous radioactive effluents to the environment, and provide appropriate containment. Based on this, the NRC staff concludes that the SFPAVS will continue to meet the requirements of GDCs 60 and 61. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the SFPAVS.

2.7.5 Auxiliary and Radwaste Area and Turbine Areas Ventilation Systems

Regulatory Evaluation

The function of the auxiliary and radwaste area ventilation system (ARAVS) and the turbine area ventilation system (TAVS) is to maintain ventilation in the auxiliary and radwaste equipment and turbine areas, permit personnel access, and control the concentration of airborne radioactive material in these areas during normal operation, during AOOs, and after postulated accidents. The NRC staff's review focused on the effects of the proposed EPU on the functional performance of the safety-related portions of these systems. The NRC's acceptance criteria for the ARAVS and TAVS are based on GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents. Specific review criteria are contained in SRP Sections 9.4.3 and 9.4.4.

Technical Evaluation

The NRC staff reviewed information provided by the licensee in its submittal that documents its review of the ARAVS and TAVS. In conducting its review, the licensee considered the impact of the proposed EPU on the non-essential ventilation systems. Essential systems are discussed in other parts of this SE.

The nonessential ventilation system provides heating, ventilation and air conditioning to non-vital areas and plant equipment. The principal components of the nonessential ventilation system are filters, fans, dampers, valves, heat exchangers, conditioning/chiller packages, and the ductwork, piping and valves. The nonessential ventilation system serves the turbine, service and all-volatile-treatment buildings.

The majority of the turbine building does not require an integrated heating, ventilation and air conditioning system. It uses independent roof vent fans, wall vent fans, windows, and steam unit heaters for ventilation and temperature control. Included in the turbine building is the main feedwater pump room. The main feedwater pump equipment cooling system blends a mixture of outside air and room air to control the room and equipment temperatures. No mechanical means of heating or cooling is provided or necessary.

The service building ventilation system consists of air handling units serving the various areas of the service building. Air from uncontaminated areas is exhausted through roof exhaust fans. Air from areas of potential contamination, such as laboratories equipped with hoods and the dress-out area are exhausted through the intermediate building controlled access area exhaust fans. Controlled access area fans 1A and 1B can draw air through a common HEPA and charcoal filter, a low-flow alarm and dampers, and discharge to the auxiliary building HEPA filter, which is exhausted by the main auxiliary building exhaust system to the main vent header.

The intermediate building and auxiliary building ventilation systems are described and evaluated in Section 2.7.6 of this SE.

The all-volatile-treatment building ventilation system provides ventilation and heating to maintain required temperatures for the all-volatile treatment (condensate demineralizer) building and the condensate booster pump area of the turbine building. For the all-volatile-treatment building, including the demineralizer area control room, ventilation and cooling is supplied through outside air intakes by fans and modulating dampers controlled by thermostats. Steam heating coils warm the air for the demineralizer area control room, when necessary. For the condensate booster pump area, ventilation and cooling is supplied by thermostatically controlled outside air intakes, fans, and dampers. No heating is required.

The nonessential ventilation system EPU heat loads were evaluated to ensure that the system is capable of performing its intended functions under normal EPU conditions. The evaluation considered whether heat load changes impacted the maximum ambient temperature for each area.

The nonessential ventilation system’s ability to provide required temperature conditions for personnel and equipment during normal operation is unaffected by the changes proposed for EPU. The increased heat loads in these areas are primarily due to changes in the main steam and feedwater system operating conditions, increased brake horsepower for the condensate booster and feedwater pumps, and small increases in electrical loads. For plant areas where temperature is controlled by air conditioning units, the small increase in heat loads is well within the capacity of the units. For plant areas that use outside air exchange to provide cooling, outside air temperature changes dominate any potential temperature changes caused by EPU.

The evaluation of the plant equipment changes for the proposed EPU did not identify any need to modify the nonessential ventilation system. There are no equipment changes as a result of EPU that could create a new potentially unmonitored airborne radioactive release path.

The nonessential ventilation systems are not within the scope of license renewal. EPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. There are no changes associated with operation of the nonessential ventilation systems at EPU conditions and the EPU does not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ARAVS and TAVS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the capability of these systems to maintain ventilation in the auxiliary and radwaste equipment areas and in the turbine area, permit personnel access, control the concentration of airborne radioactive material in these areas, and control release of gaseous radioactive effluents to the environment. Based on this, the NRC staff concludes that the ARAVS and TAVS will continue to meet the requirements of GDC-60. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the ARAVS and the TAVS.

2.7.6 Engineered Safety Feature Ventilation System

Regulatory Evaluation

The function of the engineered safety feature ventilation system (ESFVS) is to provide a suitable and controlled environment for ESF components following certain anticipated transients and DBAs. The NRC staff's review for the ESFVS focused on the effects of the proposed EPU on the functional performance of the safety-related portions of the system. The NRC staff's review also covered (1) the ability of the ESF equipment in the areas being serviced by the ventilation system to function under degraded ESFVS performance; (2) the capability of the ESFVS to circulate sufficient air to prevent accumulation of flammable or explosive gas or fuel-vapor mixtures from components (e.g., storage batteries and stored fuel); and (3) the capability of the ESFVS to control airborne particulate material (dust) accumulation. The NRC's acceptance criteria for the ESFVS are based on (1) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (2) GDC-17, insofar as it requires onsite and offsite electric power systems be provided to permit functioning of SSCs important to safety; and (3) GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents. Specific review criteria are contained in SRP Section 9.4.5.

Technical Evaluation

The NRC staff reviewed information provided by the licensee in its submittal that documents its review of the ESFVSs. In conducting its review, the licensee considered the impact of the proposed EPU on each of the essential ventilation systems.

The essential ventilation system functions to maintain temperatures within specified limits in areas containing safety-related equipment. Normal ventilation exhausts from potentially contaminated areas are filtered and the discharge is monitored for radiation. Included in the scope of the essential ventilation system are the following subsystems:

- Auxiliary building ventilation
- Intermediate building ventilation
- SAFW building ventilation
- EDG building ventilation

The auxiliary building has a nonsafety heating, ventilation, and air conditioning system, which provides clean, filtered, and tempered air to the operating floor of the auxiliary building and to the surface of the decontamination pit and spent fuel storage pool. The system exhausts air from the equipment rooms and open areas of the auxiliary building and the decontamination pit and the spent fuel pool through a closed exhaust system. The exhaust system includes a 100% capacity bank of high-efficiency particulate air filters and redundant 100% capacity fans discharging to the atmosphere via the plant vent. This arrangement ensures the proper direction of air flow for removal of airborne radioactivity from the auxiliary building. In addition to the main auxiliary building ventilation system, the RHR, SI, CS and charging pump motors are provided with additional cooling capability.

The SFPAVS is a part of the auxiliary building ventilation system. Refer to Section 2.7.4 of this SE for the evaluation of this system.

Air is introduced to the clean side of the intermediate building through two wall dampers mounted in the outside wall, and from the turbine building through a damper mounted in the wall common to both buildings. A supply fan moves air from the intermediate building clean side to its restricted area side. Two exhaust fans, located in the intermediate building restricted area side, draw air from both the clean and restricted area sides of the building and discharge to the auxiliary building discharge header plant vent duct. There are also four roof ventilators on the clean side to provide additional exhaust, and a fan mounted in a floor grating to move basement level air up to higher floor levels in the clean side. Within the intermediate building, control rod drive mechanism control cabinets are served by self-contained air conditioning units.

The SAFW pump building cooling and heating system provides heating or cooling as necessary to provide an acceptable environment for the safety-related equipment housed within the building. Each SAFW pump building cooling unit uses service water as a cooling medium and is automatically started whenever its corresponding SAFW pump is started.

The diesel generators are housed in adjacent but separate rooms, each of which is serviced by a safety-related ventilation system having two inlet fans supplying outside air. Excess air is discharged to the outdoors through automatic, pressure-actuated room vents, backdraft dampers, and wall-mounted louvers. No refrigeration or service water air cooling is used.

The changes in heat loads for ventilation subsystems in areas served by the essential ventilation system were evaluated to ensure that the ventilation systems are capable of performing their intended functions under EPU conditions including the ability of the system to control airborne particulate material accumulation.

The essential ventilation systems were reviewed for impacts as a result of EPU on any redundancies and diversities provided in the original design to ensure adequate operation with degraded components, and to prevent or dissipate flammable or explosive vapors.

The auxiliary and intermediate building, restricted side, area air temperatures are not significantly affected after implementation of the EPU. The increased heat load in the intermediate building, clean side, is primarily due to the changes in the main steam and feedwater system operating conditions. The intermediate building clean side uses outside air exchange to provide cooling, outside air temperature changes dominate any potential temperature changes caused by EPU. The EPU evaluation determined that the effect of EPU on the normal operating temperatures increased by less than 1 EF and that the maximum normal operating design temperature of 104 EF is not exceeded.

Heat loads in the standby auxiliary feedwater pump room do not increase after implementation of the EPU. Therefore, the ventilation system's ability to provide required temperature conditions for personnel and equipment is not impacted by EPU.

The EDG loading is not increased after implementation of the EPU. Therefore, the ventilation system's ability to provide the required temperature conditions for personnel and equipment is not impacted by EPU.

The evaluation of the plant equipment changes for the proposed EPU did not identify any need to modify the essential ventilation system. There are no equipment changes as a result of EPU that could change the existing capability of the essential ventilation system under degraded conditions.

Likewise, there are no equipment changes as a result of EPU that could create a new potentially unmonitored radioactive release path. Thus, following the EPU, Ginna Station will continue to meet the current licensing basis with respect to GDC 60. The effects of potential releases to the environment have been evaluated and remain within current limits following the EPU.

There are no equipment changes as a result of EPU that could affect the accumulation or dissipation of flammable or explosive vapors. Thus, following EPU, the ventilation systems will continue to circulate sufficient air to prevent flammable or explosive vapors.

The evaluation of the essential ventilation system demonstrates that no changes are required to the system. Therefore, the design capability of the system to maintain an acceptable building environment related to control airborne particulate material accumulation is not impacted.

Portions of the essential ventilation system are within the scope of license renewal. EPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. Slightly increased heat loads are well within the capability of the current ventilation systems. Because no modifications are necessary for essential ventilation system components, EPU does not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ESFVS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the ability of the ESFVS to provide a suitable and controlled environment for ESF components. The NRC staff further concludes that the ESFVS will continue to assure a suitable environment for the ESF components following implementation of the proposed EPU. The NRC staff also concludes that the ESFVS will continue to suitably control the release of gaseous radioactive effluents to the environment following implementation of the proposed EPU. Based on this, the NRC staff concludes that the ESFVS will continue to meet the requirements of GDC 4, 17, and 60. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the ESFVS.

2.7.7 Other Ventilation Systems (Containment)

Regulatory Evaluation

The NRC staff reviewed the containment ventilation system with respect to heat removal from the containment atmosphere, radioactive material removal from the containment atmosphere and the impact on containment pressure control under normal and accident conditions. The review focused on the effects of the EPU on the performance of the system. The NRC's acceptance criteria for the containment ventilation system are based on (1) GDC-4, insofar as it requires that safety-related structures, systems, and components be designed to accommodate the effects of and be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, (2) GDC-17, insofar as it requires onsite and offsite electric power systems be provided to permit functioning of safety-related structures, systems, and components, (3) GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents, and (4) GDC-61, insofar as it requires that systems containing radioactivity be designed with appropriate confinement and containment.

Technical Evaluation

The NRC staff reviewed information provided by the licensee in its submittal that documents its review of the Other Ventilation Systems (Containment). In conducting its review, the licensee considered the impact of the proposed EPU on each of the containmnent systems identified below.

Included within the scope of the containment ventilation systems are the following subsystems:

- Containment recirculating cooling and filtration system
- Control rod drive mechanism cooling system
- Reactor compartment cooling system
- Refueling water surface and purge system
- Containment auxiliary charcoal filter system
- Containment post-accident charcoal filter system
- Containment shutdown purge system
- Containment mini-purge system
- Penetration cooling subsystem

The principal components of the containment ventilation system include filters, fans, dampers, valves, heat exchangers, essential ductwork, containment isolation valves, and piping.

The containment recirculation fans, control rod drive mechanism fans, and reactor compartment fans are direct-driven units, each with standby units for redundancy. The fans and motors of these units are provided with vibration detecting devices to detect abnormal operating conditions in the early stages of the disturbance. Each of the associated systems is provided with flow switches to verify existence of air flow in the associated duct system.

Dampers in the following systems and ducts are provided with air by dual supply air mains, including primary compartment ducts, dome ducts, containment auxiliary charcoal filter systems, butterfly valves which isolate the post-accident charcoal filters, and containment purge supply and exhaust ducts. Two of the four fans and coolers plus one containment spray pump (i.e., one train of each system) are required to provide sufficient capacity to maintain the containment pressure within design limits after a LOCA or steam line break accident. The containment recirculation fan cooler electrical connections and other equipment in the containment necessary for operation of the system are capable of operating under the environmental conditions following a LOCA.

The control rod drive mechanism cooling system consists of fans and ductwork that draw air through the control rod drive mechanism shroud and eject it to the main containment volume. The reactor compartment cooling system consists of a plenum, cooling coils, fans, and ductwork arranged to supply cool air to the annulus between the reactor vessel and the primary shield and to the nuclear instrumentation external to the reactor.

The refueling water surface and purge system supplies air to the surface of the refueling cavity and exhausts from the area above the refueling manipulator crane to protect the operators during refueling operations. The containment auxiliary charcoal filter system's purpose is to absorb radioactive iodine vapor and radioactive particles that may occur as a result of normal primary system leakage inside the containment.

The containment shutdown purge system is independent of the main auxiliary building exhaust system and includes provisions for both supply and exhaust air. The supply system includes an outside air connection to roughing filters, heating coils, fans, duct system, and supply penetration with a butterfly isolation valve outside containment and a blind flange inside containment. The exhaust system includes an exhaust penetration with a butterfly isolation valve and a blind flange identical to those above, a duct system, a filter bank with high-efficiency particulate air and charcoal filters, fans, and a building exhaust vent. The shutdown purge supply and exhaust duct blind flanges inside the containment are closed during modes 1, 2, 3, and 4.

The containment mini-purge system is capable of purging containment during modes 1 and 2 at a relatively low flow rate (approximately 1500 cfm). The exhaust is through a 6-inch line to the auxiliary building charcoal filters arranged with automatic air-operated butterfly isolation valves inside and outside containment. The isolation valves are capable of closing fully against 60 psig in a maximum of 2 seconds after receiving an isolation signal. The mini-purge system is connected to the plant vent and is automatically isolated on high radiation signal.

The containment penetration cooling system is designed to prevent the bulk concrete temperature surrounding the containment penetrations from exceeding 150 EF.

The licensee evaluated changes in heat loads for ventilation subsystems in the containment were evaluated to ensure that the ventilation systems are capable of performing their intended functions under normal EPU modes.

Portions of the containment ventilation system are within the scope of license renewal. EPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. Operating the containment ventilation system at EPU conditions does not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

The licensee evaluated containment ventilation system's ability to provide the required temperature conditions for personnel and equipment in the containment during normal operation. The results of the evaluation determined that an increase in the containment bulk air temperature of approximately 1 °F from the current observed level will occur at EPU conditions. This increase in the normal operating containment bulk air temperature will not exceed the maximum normal operating bulk temperature limit of 120 EF.

Conclusion

The NRC staff has reviewed the containment ventilation system with respect to heat removal from the containment atmosphere, radioactive material removal from the containment atmosphere and the impact on containment pressure control under normal and accident conditions. The review focused on the effects of the EPU on the performance of the system. The NRC concludes that the licensee has adequately accounted for the effects of the EPU on the ability of the containment ventilation system to provide a suitable and controlled environment for the containment components. Based on this review, the NRC concludes that the containment ventilation system will continue to meet the requirements of GDCs 4, 17, 60, and 61. Therefore the staff finds the proposed EPU acceptable with respect to the containment ventilation system.

2.8 Reactor Systems

The NRC staff reviewed the following topics as indicated in the following table. New analyses are denoted by "A" (analyzed). Events that are not affected by the EPU or are bounded by other events are evaluated and denoted by "E" (evaluated).

RS-001, Matrix 8	**Ginna Licensing Report:**	**Licensing Report & SE Section**	**UFSAR Section**
Fuel System Design	Fuel System Design	2.8.1	6.3.3
Nuclear Design	Nuclear Design	2.8.2	4.3
Thermal and Hydraulic Design	Thermal and Hydraulic Design	2.8.3	4.4
Functional Design of Control Rod Drive System	Functional Design of Control Rod Drive System	2.8.4.1	3.9.4, 4.2, 7.2, 7.7.1.2, 9.4.1.2.3, 15.4
Overpressure Protection during Power Operation	Overpressure Protection during Power Operation	2.8.4.2	5.2.2.1
Overpressure Protection during Low Temperature Operation	Overpressure Protection during Low Temperature Operation	2.8.4.3	5.4.10, 7.6.1, 5.2.2.2
Residual Heat Removal System	Residual Heat Removal System	2.8.4.4	5.4.5
Emergency Core Cooling System	Emergency Core Cooling System	2.8.5.6.3	6.3
Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator (SG) Relief or Safety Valve	Decrease in FW Temp (E)	2.8.5.1.1	15.1.1
	Increase in FW Flow (A)	2.8.5.1.1	15.1.2
	Excessive Load Increase (E)	2.8.5.1.1	15.1.3
	Inadvertent Opening of a SG Relief/Safety Valve (E)	2.8.5.1.1	15.1.4
	Combined SG ARV and Feedwater Control Valve Failures (A)	2.8.5.1.1	15.1.6
Steam System Piping Failures Inside and Outside of Containment	Rupture of a Steam Pipe – HZP Core Response (A)	2.8.5.1.2	15.1.5
	Rupture of a Steam Pipe – HFP Core Response (A)	2.8.5.1.2	15.1.5

RS-001, Matrix 8	Ginna Licensing Report:	Licensing Report & SE Section	UFSAR Section
Loss of External Load; Turbine Trip, Loss of Condenser Vacuum	Steam Pressure Regulator Malfunction (E)	2.8.5.2.1	15.2.1
	Loss-of-External-Electrical Load (A)	2.8.5.2.1	15.2.2
	Turbine Trip (E)	2.8.5.2.1	15.2.3
	Loss of Condenser Vacuum (E)	2.8.5.2.1	15.2.4
Loss of Nonemergency AC Power to the Station Auxiliaries	Loss-of-Offsite-ac-Power to the Station Auxiliaries (A)	2.8.5.2.2	15.2.5
Loss of Normal FW Flow	Loss of Normal Feedwater Flow (A)	2.8.5.2.3	15.2.6
Feedwater System Pipe Breaks Inside and Outside Containment	Feedwater System Pipe Breaks (A)	2.8.5.2.4	15.2.7
Loss of Forced Reactor Coolant Flow Including Trip of Pump Motor and Flow Controller Malfunctions	Flow Coastdown Accident (A)	2.8.5.3.1	15.3.1
Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break	Locked Rotor Accident (A)	2.8.5.3.2	15.3.2
Uncontrolled Control Rod Assembly Withdrawal from a Subcritical or Low Power Startup Condition	Uncontrolled RCCA Withdrawal from a Subcritical Condition (A)	2.8.5.4.1	15.4.1
Uncontrolled Control Rod Assembly Withdrawal at Power	Uncontrolled RCCA Withdrawal at Power (A)	2.8.5.4.2	15.4.2
Control Rod Misoperation (System Malfunction or Operator Error)	RCCA Drop (A)	2.8.5.4.3	15.4.6
Startup of an Inactive Loop or Recirculation Loop at an Incorrect Temperature	Startup of an Inactive RCL (E)	2.8.5.4.4	15.4.3

RS-001, Matrix 8	Ginna Licensing Report:	Licensing Report & SE Section	UFSAR Section
Chemical and Volume Control System Malfunction that Results in a Decrease in Boron Concentration in the Reactor Coolant	Boron Dilution (A)	2.8.5.4.5	15.4.4
Spectrum of Rod Ejection Accidents	RCCA Ejection (A)	2.8.5.4.6	15.4.5
Spectrum of Rod Drop Accidents	RCCA Drop (A)	2.8.5.4.3	15.4.6
Inadvertent Operation of ECCS and Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory	CVCS Malfunction (E)	2.8.5.4.5	
Inadvertent Opening of a PWR Pressurizer Pressure Relief Valve	Inadvertent Opening of a Pressurizer Safety or Relief Valve (A)	2.8.5.6.1	15.6.1
Steam Generator Tube Rupture	Steam Generator Tube Rupture	2.8.5.6.2	15.6.3
Loss-of Coolant Accidents Resulting from Spectrum of Postulated Piping Breaks within the Reactor Coolant Pressure Boundary	Emergency Core Cooling System and LOCAs	2.8.5.6.3	15.6.4
Anticipated Transients Without Scram	ATWS (A)	2.8.5.7	15.8
New Fuel Storage	New Fuel Storage	2.8.6.1	9.1.2.4.1
Spent Fuel Storage	Spent Fuel Storage	2.8.6.2	9.1.2.4.1

2.8.1 Fuel System Design

Regulatory Evaluation

The fuel system consists of arrays of fuel rods, burnable poison rods, spacer grids and springs, end plates, and reactivity control rods. The NRC staff reviewed the fuel system to assure that (1) the fuel system is not damaged as a result of normal operation and anticipated operational occurrences (AOOs), (2) fuel system damage is never so severe as to prevent control rod insertion when it is required, (3) the number of fuel rod failures is not underestimated for postulated accidents, and (4) coolability is always maintained. The NRC staff's review covered fuel system damage mechanisms, limiting values for important parameters, and performance of the fuel system during normal operation, AOOs, and postulated accidents. The NRC's acceptance criteria are based on (1) 10 CFR 50.46, insofar as it establishes standards for the calculation of emergency core cooling system (ECCS) performance and acceptance criteria for that calculated performance; (2) GDC 10, insofar as it requires that the reactor core be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs; (3) GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; and (4) GDC-35, insofar as it requires that a system to provide abundant emergency core cooling be provided to transfer heat from the reactor core following any LOCA. Specific review criteria are contained in SRP Section 4.2 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The licensee's application for an EPU, from 1520 MWt to 1775 MWt, includes a transition from the current fuel system, the Westinghouse Optimized Fuel Assembly (OFA) with ZIRLO™ cladding to the Westinghouse 14x14 Vantage+ (422V+) fuel design. The core fuel assemblies of the current OFA design, contain 0.400 inch diameter rods, and the fuel assemblies of the 422V+ design contain 0.422 inch diameter rods.

The licensee's current fuel system design consists of the Westinghouse OFA structure with ZIRLO™ alloy as a fuel cladding material. The licensing of ZIRLO™ alloy as a fuel cladding material is documented in Westinghouse Report WCAP-12610-P-A (Reference 40). The improvement of ZIRLO™ over previous Westinghouse cladding materials was such that several licensees implemented the cladding material aspect of WCAP-12610-P-A without changing the physical structure of the fuel assemblies or fuel rods. On March 3, 1999, the NRC approved Ginna's use of the ZIRLO™ alloy as a fuel cladding material (Reference 41).

The 422V+ fuel design is a modification of the physical structure of the WCAP-12610-P-A fuel design. The 422V+ modifications were licensed under the Westinghouse fuel criteria evaluation process (FCEP) (Reference 42). FCEP is a process whereby Westinghouse may make minor changes to its fuel designs without prior NRC approval. Westinghouse is, however, required to notify the NRC when such changes are made. FCEP Notification for the initial 422 V+ fuel design was made to the NRC on September 9, 1997 (Reference 43). The 422 V+ fuel design, as defined by that FCEP Notification, is currently in use at Kewaunee and Point Beach Units 1 and 2. Therefore, current operating experience supports operation of current 422 V+ fuel design in a commercial power reactor commensurate with the power level requested by Ginna.

To improve the design and accommodate Ginna, several changes are being made to the physical structure of the 422V+ fuel design. Those changes were also made by Westinghouse via FCEP. The changes, as described in Westinghouse's FCEP Notification (Reference 44) are:

- A balanced vane pattern on the mid-grids, as was done on Westinghouse 17x17 Robust Fuel Assembly (RFA) design to reduce assembly vibration,

- A modification to increase grid to rod contact in the mid-grids to provide additional grid-to-rod fretting margin,

- Incorporate a tube-in-tube guide thimble design, to provide additional incomplete rod insertion margin,

- Increased fuel rod length to accommodate rod internal pressure, and

- The number of mid-grids was increased to seven, to match Ginna's current OFA design. (Note: A five mid-grid design remains available for use at Kewaunee and Point Beach Units 1 and 2.)

In its acceptance of WCAP-12488 (Reference 42) the NRC found the FCEP process to be consistent with the review criteria in SRP Section 4.2. In reviewing the original FCEP evaluation of the revised 422V+ fuel system design, the NRC staff noted that whereas the increased fuel rod length was identified in a table of parameters attached to the FCEP, the effect of the increased fuel rod length was not addressed in the justifications provided in the text. Therefore, Westinghouse issued a revised FCEP Notification (Reference 44), that included the effects of the increased fuel rod length on rod internal pressure and axial growth acceptance criteria. The revised FCEP Notification contains a similar situation with respect to the assembly loss coefficient. Westinghouse, through testing and analysis, determined the changes to the mid-grid did not affect the loss coefficients associated with the mid-grid. However, adding two mid-grids to the assembly increased the overall assembly loss coefficient. Again, the seven (7) mid-grid flow loss coefficient is identified in a table of parameters attached to the FCEP, but the effect was not addressed in the justifications provided in the text, specifically with respect to thermal-hydrodynamic stability and fuel assembly hold down force. As Ginna is the only licensee expected to exercise the seven (7) mid-grid option on the revised 422V+ fuel system design, information the licensee provided was used to evaluate the change.

The licensee provided additional details with respect to its specific application of the revised 422V+ fuel system design. Specific details were provided for hydriding and corrosion performance to demonstrate acceptable performance. Specific details were provided for fuel assembly hold-down force to demonstrate acceptable performance. Specific details were provided for fuel assembly structural response to seismic/LOCA loads to demonstrate acceptable performance.

The licensee evaluated the proposed Westinghouse revised 422V+ fuel system design compatibility with its current fuel system design (OFA with ZIRLO™). The original WCAP-12610-P-A fuel system was designed to be compatible with the OFA design. The changes associated with the revised 422V+ fuel system design do not invalidate that compatibility. Adding two mid-grids ensures Ginna's current fuel design and the revised 422V+ fuel system design are mechanically compatible. The two additional mid-grids raises the fuel assembly loss coefficient for the 422V+ fuel system design. However, that fuel assembly loss coefficient is still less than that of the OFA with ZIRLO™ fuel that Ginna is currently using. Therefore, during the transition cycles there will be a flow differential between the OFA with ZIRLO™ and 422V+ fuel system designs.

Westinghouse and the licensee used a combination of analysis and testing to demonstrate the compatibility of the two fuel designs. Testing consisted of fuel assembly compatibility test system

(FACTS) testing for hydraulic and vibration tests, and long term wear tests using the vibration investigation and pressure drop experimental research (VIPER) loop, and strength tests for the structural vitality of the tube-in-tube thimble design. That testing, in part, was used to establish the overall assembly loss coefficient (Reference 29). Analyses include the use of approved methodologies PAD 4.0 (Reference 46), WEGAP (Reference 47), and Westinghouse Reload Safety Evaluation Methodology (Reference 48). These are the same codes and methods used to evaluate the transition of other licensees to the 422V+ fuel design at an EPU (References 49 and 50).

The NRC staff's review of the fuel system design focused mainly upon the performance of the fuel rods, cladding, and assemblies under the steady-state and transient operating conditions that would be characteristic of the Ginna core, when operating at EPU conditions. The staff reviewed the original submittal, supplements, responses to RAIs, and audited (Reference 24) applicable records at the Westinghouse facility in Monroeville, PA.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the fuel system design of the fuel assemblies, control systems, and reactor core. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the fuel system and demonstrated that (1) the fuel system will not be damaged as a result of normal operation and AOOs, (2) the fuel system damage will never be so severe as to prevent control rod insertion when it is required, (3) the number of fuel rod failures will not be underestimated for postulated accidents, and (4) coolability will always be maintained. Based on this, the NRC staff concludes that the fuel system and associated analyses will continue to meet the requirements of 10 CFR 50.46, GDC 10, GDC 27, and GDC 35 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the fuel system design.

2.8.2 Nuclear Design

Regulatory Evaluation

The NRC staff reviewed the nuclear design of the fuel assemblies, control systems, and reactor core to ensure that fuel design limits will not be exceeded during normal operation and AOOs, and that the effects of postulated reactivity accidents will not cause significant damage to the RCPB or impair the capability to cool the core. The NRC staff's review covered core power distribution, reactivity coefficients, reactivity control requirements and control provisions, control rod patterns and reactivity worths, criticality, burnup, and vessel irradiation. The NRC's acceptance criteria are based on (1) GDC 10, insofar as it requires that the reactor core be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs; (2) GDC 11, insofar as it requires that the reactor core be designed so that the net effect of the prompt inherent nuclear feedback characteristics tends to compensate for a rapid increase in reactivity; (3) GDC 12, insofar as it requires that the reactor core be designed to assure that power oscillations, which can result in conditions exceeding SAFDLs, are not possible or can be reliably and readily detected and suppressed; (4) GDC-13, insofar as it requires that instrumentation and controls be provided to monitor variables and systems affecting the fission process over anticipated ranges for normal operation, AOOs and accident conditions, and to maintain the variables and systems within prescribed operating ranges; (5) GDC 20, insofar as it requires that the protection system be designed to initiate the reactivity control systems automatically to assure that acceptable fuel design limits are not exceeded as a result of AOOs and to automatically initiate operation of systems and components important to safety under accident conditions; (6) GDC 25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems; (7) GDC 26, insofar as it requires that two independent reactivity control systems be provided, with both systems capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes; (8) GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; and (9) GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other RV internals so as to significantly impair the capability to cool the core. Specific review criteria are contained in SRP Section 4.3 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The licensee's application for an EPU includes a transition from the current fuel system, the Westinghouse OFA with ZIRLO™ cladding to the Westinghouse 422V+ fuel design.

The EPU and fuel system change can affect key nuclear safety parameters, such as core power distribution, reactivity coefficients, reactivity control requirements and control provisions, control rod patterns and reactivity worths, criticality, burnup, and vessel irradiation. Many of these parameters are used in accident analyses, as discussed in the licensing report and Chapter 15 of the UFSAR.

The licensee evaluated the Ginna nuclear design bases and methodologies for the use of Westinghouse 422V+ fuel design considering the uprated core power levels (1775 MWt core power). The following nuclear design parameters are changed:

Parameter	OFA with ZIRLO™	422V+
Power (MWt)	1520	1775
Fuel Rod Length (inches)	149.2	152.8
Fuel Stack Height (inches)	141.4	143.25
Pellet Diameter (inches)	0.34	0.37
Pellet Length (inches)	0.41	0.44
Annular Pellet ID (inches)	0.17	0.18
Annular Pellet OD (inches)	0.34	0.37

Parameter	OFA with ZIRLO™	422V+
Pellet-to-Clad Gap (mils)	3.5	3.7
Cladding OD (inches)	0.400	0.422
Grid Strip Material	Zircaloy-4	ZIRLO™
$F^N_{\Delta H}$	1.75	1.72 (422V+) 1.60 (OFA)
F_Q	2.50 (Non-LOCA) 2.45 (LOCA)	2.60
Shutdown Margin	2.45 (N–1 Loops) 1.80 (N Loops)	1.80 (N–1 Loops) 1.30 (N Loops)
MDC ($\Delta K/g/cm^3$)	0.43	0.45
T_{avg} (EF)	561	564.6 to 576.0
RCCA Elevation (inches)	Baseline	+3
Total Rod Worth (%ΔK)	4.0000	3.5000

A similar version of the 422V+ fuel design is currently in use at Kewaunee and Point Beach Units 1 and 2. Therefore, current operating experience supports operation of current 422V+ fuel design in a commercial power reactor commensurate with the power level proposed by Ginna.

The licensee has made no changes to the nuclear design philosophy or methods as part of the transition to the 422V+ fuel design and EPU. Ginna's nuclear design philosophy and methods are captured in WCAP-9272-P-A (Reference 48).

In an application dated April 29, 2005 (Reference 18), the licensee requested implementation of WCAP-10216-P-A (Reference 52). WCAP-10216-P-A contains two parts. One part describes a method for determining an acceptable Axial Flux Differential (AFD) profile. The other part describes an alternate means for monitoring the heat flux hot channel factor (F_Q). The NRC staff approved Ginna's use of WCAP-10216-P-A on February 15, 2006 (Reference 53). These changes along with those reflected in the table above were used in the licensee's EPU analysis.

As a result of the EPU and fuel system change there has been no change to the rod cluster control assemblies (RCCAs) or hardware of the control rod drive system. The RCCAs rest approximately three (3) inches higher in the 422V+ fuel design than the current OFA with ZIRLO™ fuel design when fully inserted. This necessitates several changes with respect to the calibration, scaling, and setpoints associated with the reactor protection system (RPS) associated with RCCA position indication. The licensee has determined that the change in elevation had a minimal impact on shutdown margin. The table above indicates a decrease in the total RCCA reactivity worth. This decrease, which is incorporated into the accident analyses, is due to the synergistic effects of the EPU and fuel system change. The licensee determined the estimated RCCA insertion time is 1.42 seconds, which is less than the TS limit of 1.80 seconds (Reference 25 and 29).

The licensee performed transition and equilibrium core analyses to demonstrate that the nuclear design is acceptable and satisfies the acceptance criteria of SRP Section 4.3. Standard NRC-approved Westinghouse reload design philosophy (Reference 48) that evaluates the reload core key safety parameters such as power distributions, peaking factors, rod worths and reactivity parameters was applied. The licensee performed all applicable analyses using NRC-approved methods and computer codes, and demonstrated that all applicable Westinghouse design limits and acceptance criteria were satisfied for the proposed EPU and 422V+ fuel design. Standard Westinghouse nuclear design analytical methods and models (References 48, 54, and 55) were applied to evaluate the neutronic behavior of both the Westinghouse 422V+ fuel and the current OFA fuel through the transition cores. These are the same codes and methods used to evaluate the transition of other licensees' cores to the 422V+ fuel design (References 49 and 50).

The licensee developed three representative core loading patterns for performing the transition core analyses. Each core loading pattern was evaluated at the low and high end for the new range of core average temperatures. The first transition cycle model was used to capture the initial and predominant transition core effects. A second transition cycle model and a third, all Westinghouse 422V+, core model were developed to capture the core characteristics through the all 422V+ loaded core. The loading patterns were developed based on projected energy requirements of approximately 510 effective full-power days (EFPDs) for Ginna. The licensee's safety analyses support a maximum nuclear enthalpy rise hot channel factor ($F^N_{\Delta H}$) limit of 1.72, and a total peaking factor (F_Q) limit of 2.60. These models were developed to demonstrate that adequate margin exists between typical safety parameter values and the corresponding limits to allow flexibility in designing actual reload cores. Cycle specific core reload design analyses will continue to verify the acceptability of future designed 422V+ core designs for Ginna in accordance with WCAP-9272-P-A. Use of WCAP-9272-P-A provides reasonable assurance that actual cycle parameters will be bounded by the transient analyses, or the affected transients will be re-evaluated/re-analyzed using NRC-approved methods and computer codes.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effect of the proposed EPU and fuel system change on the nuclear design of the fuel assemblies, control systems, and reactor core. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the nuclear design and has demonstrated that the fuel design limits will not be exceeded during normal operation or AOOs, and that the effects of postulated reactivity accidents will not cause significant damage to the RCPB or impair the capability to cool the core. Based on this evaluation and in coordination with the reviews of the fuel system design, thermal and hydraulic design, and transient and accident analyses, the NRC staff concludes that the nuclear design of the fuel assemblies, control systems, and reactor core will continue to meet the applicable requirements of GDCs 10, 11, 12, 13, 20, 25, 26, 27, and 28. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the nuclear design.

2.8.3 Thermal and Hydraulic Design

Regulatory Evaluation

The NRC staff reviewed the thermal and hydraulic design of the core and the RCS to confirm that the design (1) has been accomplished using acceptable analytical methods, (2) is equivalent to or a justified extrapolation from proven designs, (3) provides acceptable margins of safety from conditions which would lead to fuel damage during normal reactor operation and AOOs, and (4) is not susceptible to thermal-hydraulic instability. The review also covered hydraulic loads on the core and RCS components during normal operation and DBA conditions and core thermal-hydraulic stability under normal operation and anticipated transients without scram (ATWS) events. The NRC's acceptance criteria are based on (1) GDC 10, insofar as it requires that the reactor core be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs; and (2) GDC 12, insofar as it requires that the reactor core and associated coolant, control, and protection systems be designed to assure that power oscillations, which can result in conditions exceeding SAFDLs, are not possible or can reliably and readily be detected and suppressed. Specific review criteria are contained in SRP Section 4.4 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The licensee's request for an EPU includes a transition from the current fuel system, the Westinghouse OFA with ZIRLO™ cladding, to the Westinghouse 422V+ fuel design.

The EPU analyses are based upon the EPU and the transition to the 422V+ fuel design. Departure from nucleate boiling (DNB) performance is dependent upon the effects of fuel rod bow and bypass flow, and flow redistribution, due to the differing local hydraulic resistances in a core containing fuel assemblies of two designs. The licensee considered fuel hydraulic compatibility during the transition from an all OFA core through mixed-fuel cores to an all 422V+ core. This included the effects of hydraulic compatibility associated with the relatively higher resistance fuel assemblies, of the OFA design, on assembly lift forces, and core stored energy. The thermal and hydraulic design calculations were also used to determine the fuel temperature and pressure data that were input to the various safety analyses. The fuel temperature and pressure data, that were used in the EPU safety analyses were chosen to bound the current OFA fuel assembly design and the new 14x14 422V+ fuel assembly design.

Key differences between the OFA and the 422V+ designs are:

- fuel rod outer diameter is increased from 0.400 inches to 0.422 inches
- uncoated pellet reference diameter is increased from 0.34 inches 0.37 inches
- grid centerline elevations for the top grid do not match
- rod internal plenum volume is increased
- fuel rod stack height is increased from 141.4 inches to 143.25 inches

The core thermal-hydraulic sub-channel analysis code that was used for the EPU analyses was VIPRE-01 (Reference 35). Table 2.8.3-1 of the licensing report lists the thermal-hydraulic parameters for the current design at 1520 MWt with OFA fuel, as well as for the EPU design at

1775 MWt with the OFA and 422V+ fuel designs. The following parameters from Table 2.8.3-1 were used in the VIPRE-01 model:

- Reactor core heat output
- Heat generated in fuel (%)
- Nominal vessel/core inlet temperature
- Nuclear enthalpy rise hot-channel factor
- Pressurizer/core pressure
- Thermal design flow (gpm)

The thermal-hydraulic design criteria applied to the EPU are unchanged from those that were applied for the Ginna UFSAR. For the EPU, the licensee applied the Advanced Setpoints Methodology (Reference 36), and substituted the VIPRE-01 code for the THINC IV code. Both codes, and the Advanced Setpoints Methodology have been approved by the NRC. Other approved methods applied for the EPU were the Revised Thermal Design Procedure (RTDP) (Reference 37), the WRB-1 DNB correlation (Reference 38), the W-3 correlation, and the Standard Thermal Design Procedure (STDP).

The reactor core is designed to meet two thermal and hydraulic criteria:

1. There is at least a 95% probability that DNB will not occur on the limiting fuel rods during MODES 1 and 2, operational transients, or any condition of moderate frequency at a 95% confidence level.
2. No fuel melting during any anticipated normal operating condition, operational transients, or any conditions of moderate frequency.

Flow redistribution occurs between adjacent fuel assemblies with different hydraulic resistances, reducing the flow in the higher-resistance assemblies. Crossflow can also be caused by local hydraulic resistance differences, such as differences in grid elevations and resistances. Flow redistribution affects both mass velocity and enthalpy distribution, which, in turn, affects DNB. This is handled by imposing a transition core DNB ratio (DNBR) penalty due to flow redistribution. DNBR is defined as the predicted critical heat flux that would result in a DNB (or DNB heat flux) divided by the actual heat flux. The DNBR limit is defined such that there is at least a 95% probability, at a 95% confidence level, that the hot fuel rod in the core will not experience a DNB when the calculated DNBR is higher than the DNBR limit. The DNBR penalty is a function of the number of OFA fuel assemblies present in the core, due to the higher flow resistance of these assemblies.

The NRC staff determined that the licensee has considered the effects of the EPU conditions and transition core flow redistribution, and used accepted codes and methods to perform the thermal and hydraulic design of the Ginna core. The staff also determined that the resulting thermal and hydraulic design parameters, used in safety analyses, will conservatively represent the transition core under EPU conditions.

<u>Conclusion</u>

The NRC staff has reviewed the licensee’s analyses related to the effects of the proposed EPU on the thermal and hydraulic design of the core and the RCS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the thermal and hydraulic design and demonstrated that the design has been accomplished using acceptable analytical methods, and provides acceptable margins of safety from conditions that would lead to fuel damage during normal reactor operation and AOOs. Based on this, the NRC staff concludes that the thermal and hydraulic design will continue to meet the requirements of GDCs 10 and 12 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to thermal and hydraulic design.

2.8.4 Emergency Systems

2.8.4.1 Functional Design of Control Rod Drive System

Regulatory Evaluation

The NRC staff's review covered the functional performance of the control rod drive system (CRDS) to confirm that the system can effect a safe shutdown, respond within acceptable limits during AOOs, and prevent or mitigate the consequences of postulated accidents. The review also covered the CRDS cooling system to ensure that it will continue to meet its design requirements. The NRC's acceptance criteria are based on (1) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (2) GDC 23, insofar as it requires that the protection system be designed to fail into a safe state; (3) GDC 25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems; (4) GDC 26, insofar as it requires that two independent reactivity control systems be provided, with both systems capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes; (5) GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; (6) GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other RV internals so as to significantly impair the capability to cool the core; and (7) GDC 29, insofar as it requires that the protection and reactivity control systems be designed to assure an extremely high probability of accomplishing their safety functions in event of AOOs. Specific review criteria are contained in SRP Section 4.6.

Technical Evaluation

The licensee's EPU request includes a transition from the current fuel system, the Westinghouse OFA with ZIRLO™ cladding to the Westinghouse 422V+ fuel design.

The proposed EPU would affect the CRDS via the transition from the current OFA with ZIRLO™ fuel system design to the 422V+ fuel system design and the EPU-related increase in temperature in the CRDS region. The EPU will increase the reactor coolant system (RCS) average temperature from 561 EF to 576 EF. The increase in RCS average temperature is expected to increase vessel head temperature from 576.8 EF to 599.2 EF. Also, RCCAs, when fully inserted, would rest approximately three (3) inches higher in the 422 V+ fuel assemblies than in the current OFA with ZIRLO™ fuel assemblies.

There are no physical changes to the CRDS, operating coil stacks, power supplies, solid state electronic control cabinets, or the control rod drive cooling system. Changes to the microprocessor rod position indication (MPRI) system are being made to accommodate the RCCA elevation difference noted above. In addition, minor changes such as recalibration, rescaling, and setpoint changes to the reactor protection control system are required to facilitate the fuel design changes and the changes in operating conditions associated with operation at EPU conditions. These changes are necessary to assure proper rod position indication to the plant operators and proper response by the RPS. The effects of the change in elevation on the nuclear design are addressed in Section 2.8.2, Nuclear Design.

As noted above, the licensee has determined the EPU will result in an RCS average temperature increase from 561 EF to 576.8 EF, and a vessel head temperature increase from 576.8 EF to 599.2 EF. The licensee applied the RCS temperature increase to the current CRDS coil temperature of 321 EF to estimate that the post-EPU coil temperature would be 334 EF. It would have been more appropriate, given the proximity of the CRDS coils to the vessel head, to apply the temperature increase of the vessel head. This would result in a CRDS coil temperature of approximately 344 EF. The licensee determined energizing the CRDS coils will raise their temperature by 14 EF. This brings the total maximum temperature for the CRDS coils to 358 EF. Although the staff’s estimate is higher than the licensee’s estimate, it is still well below the licensee’s design limit of 392 EF. Therefore, the staff finds this to be acceptable.

The licensee has determined the temperature increase at the CRDS coils will raise the coolant temperature by about 6.7 EF at the exit of the coils. This would bring the final exit temperature of the cooling system water to approximately 184.7 EF, well below the licensee’s 213 EF limit. The 6.7 EF increase would result in increasing the containment heat load by approximately 211,000 BTU/hr. The licensee has determined the total temperature increase for the containment due to all aspects of the EPU to be approximately 1 EF. The containment will still meet its design limits. Therefore, the staff finds this to be acceptable.

<u>Conclusion</u>

The NRC staff has reviewed the licensee’s analyses related to the effects of the proposed EPU on the functional design of the CRDS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system and demonstrated that the system’s ability to effect a safe shutdown, respond within acceptable limits, and prevent or mitigate the consequences of postulated accidents will be maintained following the implementation of the proposed EPU. The NRC staff further concludes that the licensee has demonstrated that sufficient CRDS cooling exists to ensure the system’s design bases will continue to be satisfied upon implementation of the proposed EPU. Based on this, the NRC staff concludes that the fuel system and associated analyses will continue to meet the requirements of GDCs 4, 23, 25, 26, 27, 28, and 29 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the functional design of the CRDS.

2.8.4.2 Overpressure Protection During Power Operation

Regulatory Evaluation

Overpressure protection for the RCPB during power operation is provided by relief and safety valves and the RPS. The NRC staff's review covered pressurizer relief and safety valves and the piping from these valves to the quench tank and RCS relief and safety valves. The NRC's acceptance criteria are based on (1) GDC 15, insofar as it requires that the RCS and associated auxiliary, control, and protection systems be designed with sufficient margin to assure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including AOOs and (2) GDC 31, insofar as it requires that the RCPB be designed with sufficient margin to assure that it behaves in a nonbrittle manner and that the probability of rapidly propagating fracture is minimized. Specific review criteria are contained in SRP Section 5.2.2 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

In response to a staff RAI, the licensee provided the results of analyses (Reference 29) to demonstrate that the Ginna safety valves will have the relief capacity to limit the RCS pressure to less than 110% of the RCPB design pressure (Reference 39), under the proposed EPU conditions. The analyses were based upon the most severe abnormal operating transient, a full load rejection, assuming that the reactor is tripped from the second safety grade signal that is generated by the RPS. The analysis results also indicate that there is sufficient margin to account for uncertainties in design and operation of the plant. These analyses, which were consistent with the review criteria of SRP 5.2.2, Section II.A, were repeated by the staff, using the LOFTRAN code (Reference 29). The staff's results confirmed the licensee's conclusions, which were based upon RETRAN (Reference 32), that sufficient relief capacity exists to protect the plant under the proposed EPU conditions. In the staff's analysis, the reactor is tripped by the OTΔT signal, which is generated about five seconds after the high pressurizer pressure signal, and the maximum RCS pressure attained is about 2725 psia, or 25 psi below the 110% of RCPB design pressure acceptance criterion. The maximum SG pressure is also acceptable.

The NRC staff finds the licensee's analyses acceptable because they were performed in accordance with the review criteria of SRP 5.2.2, Section II.A, and demonstrated that the Ginna safety valves continue to have sufficient capacity to protect the plant under the proposed EPU conditions.

Conclusion

The NRC staff has reviewed and confirmed the licensee's analyses related to the effects of the proposed EPU on the overpressure protection capability of the plant during power operation. The NRC staff concludes that the licensee has (1) adequately accounted for the effects of the proposed EPU on pressurization events and overpressure protection features and (2) demonstrated that the plant will continue to have sufficient pressure relief capacity to assure that pressure limits will not be exceeded. Based on this, the NRC staff concludes that the overpressure protection features will continue to provide adequate protection to meet GDC 15 and GDC 31 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to overpressure protection during power operation.

2.8.4.3 Overpressure Protection During Low Temperature Operation

Regulatory Evaluation

Overpressure protection for the RCPB during low temperature operation of the plant is provided by pressure-relieving systems that function during the low temperature operation. The NRC staff's review covered relief valves with piping to the quench tank, the makeup and letdown system, and the residual heat removal (RHR) system that may be operating when the primary system is water solid. The NRC's acceptance criteria are based on (1) GDC 15, insofar as it requires that the RCS and associated auxiliary, control, and protection systems be designed with sufficient margin to assure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including AOOs; and (2) GDC 31, insofar as it requires that the RCPB be designed with sufficient margin to assure that it behaves in a nonbrittle manner and the probability of rapidly propagating fracture is minimized. Specific review criteria are contained in SRP Section 5.2.2.

Ginna was granted a renewed license in May 2004. As part of that license extension review, the NRC staff reviewed and accepted the following topics:

- RV Material Surveillance Program (licensing report Section 2.1.1)
- Pressure Temperature Limits and Upper Shelf Energy (licensing report Section 2.1.2)
- Pressurized Thermal Shock (licensing report Section 2.1.3) and
- Overpressure Protection During Low Temperature Operation (licensing report Section 2.8.4.3).

Therefore, the scope of this SE is to examine the impact of the power uprate for the full term of the current license.

Technical Evaluation

a. Reactor Vessel Material Surveillance Program (Section 2.1.1 of the licensing report)

The structural integrity of the ferritic materials of the pressure vessel depends on its chemical composition and the amount of neutron irradiation it receives. The staff's review is focused upon the fast neutron fluence values resulting from the proposed EPU.

The Reactor Vessel Material Surveillance Program is governed by the following regulations or guidance:

- Appendix H to 10 CFR Part 50, regarding monitoring changes to the pressure vessel material fracture toughness, and
- 10 CFR 50.60, regarding the requirement to comply with Appendix H to 10 CFR Part 50.
- RG 1.190, "Calculational and Dosimetry Methods for determining Pressure Vessel Neutron Fluence," regarding the attributes of vessel fluence methodologies acceptable to the staff.

It is necessary to evaluate the impact of the proposed EPU on vessel fast neutron fluence and its effect on the surveillance capsule withdrawal schedule, and the acceptability of the projected surveillance capsule fluence values.

The calculations for the projected surveillance capsule fluence were carried out using methods adhering to the guidance in RG 1.190. The neutron source term accounted for the proposed EPU. The cross sections used were derived from the ENDF/B-VI data file and the approximations for the inelastic scattering and the quadrature are those recommended in RG 1.190. The values so derived are, therefore, acceptable.

b. Pressure Temperature Limits and Upper Shelf Energy (Section 2.1.2 of the licensing report)

Ginna has a Pressure Temperature Limits Report (PTLR) that describes the methodology the licensee can use to update the PT limits pursuant to 10 CFR 50.59. In addition, the PT limits have been evaluated as part of the review for May 2004 license renewal.

Pressure temperature (PT) limits are established to protect the pressure vessel during normal operation including AOOs and hydrostatic testing. The PT limit methodology accounts for the material embrittlement and uses linear fracture mechanics to satisfy the requirements of Appendix G to 10 CFR Part 50 (Appendix G). The applicable regulations and guidance are:

- GDC 14, regarding design, fabrication, erection and testing to assure extremely low probability of a rapidly propagating fracture,
- GDC 31, regarding the design margin needed to assure that the reactor coolant pressure boundary behaves in a non-brittle manner,
- Appendix G, regarding fracture toughness requirements for the RCPB,
- 10 CFR 50.60, regarding compliance with the requirements of Appendix G, and
- RG 1.190, regarding the attributes of neutron fluence calculational methods acceptable to the staff.

In order to evaluate the acceptability of the proposed vessel fluence values the staff considered the only change that was made since the PT limits were last approved: the value of the neutron source due to the EPU, applied for the period of the license extension. The methodology used by the licensee to assess the EPU neutron source value on PT limits has been accepted. The licensee stated that the calculations adhere to the guidance in RG 1.190, and that the values are reasonable, compared to similar vessel values. Therefore, the staff finds that the projected vessel fluence values, to 54 EFPY of operation, are acceptable.

c. Pressurized Thermal Shock (Section 2.1.3 of the licensing report)

The PTS evaluation in terms of RT_{PTS} provides the means for assessing the vessel susceptibility to PTS brittle fracture. The RT_{PTS} is calculated at the end of the extended license. In addition to GDCs 14 and 31, which pertain to the vessel material requirements, the RT_{PTS} screening criteria are specified in 10 CFR 50.61. The guidance in RG 1.190 is applicable to the fluence calculational methods.

The only change that was made since the PT limits were last approved is the value of the neutron source (due to the EPU). Since the proposed increase is reasonable, the staff finds the proposed fluence value for 54 EFPYs for the calculation of the 10 CFR 50.61 PTS screening criteria are acceptable.

d. Overpressure Protection During Low Temperature Operation (Section 2.8.4.3)

Overpressure protection during low temperature operation (LTOP) is required to prevent brittle fracture of the RCPB. At Ginna, this is accomplished with: (1) two power operated relief valves (PORVs) in Modes 4, 5, and 6, and no safety injection capability, or (2) a 1.1 square inch pressure vessel vent with the RCS depressurized and at most one safety injection pump capable of injecting. The focus of review is the acceptability of the vessel fluence and the LTOP mass and heat injection transient analyses for the determination of the LTOP setpoints.

The acceptance criteria are specified in GDC 15, which pertains to the control and protection system design's ability to provide sufficient margin for normal operation and AOOs, and GDC 31, which requires that the RCPB be designed with sufficient margin to assure it behaves in a non-brittle manner during normal operation and AOOs. RG 1.190, describes the attributes of calculational methodologies acceptable to the staff for the evaluation of the projected fluence values.

As mentioned above, the projected fluence values were calculated using methods consistent with the guidance of RG 1.190, and therefore, they are acceptable.

Ginna evaluated mass and heat addition transients for the purpose of determining the LTOP setpoints. The existing analyses indicate that the mass addition transient is limiting, based upon the assumption that let down is isolated and three charging pumps are operating. However, since a PORV activation requires isolation of the safety injection pumps, a transient of mass addition due to safety injection is not credible. For this limiting mass addition transient, the RCS coolant temperature is initialized at 60 EF and pressure at 315 psig. The pressurizer is assumed solid and two RCPs running. This transient is assumed to be terminated manually in 10 minutes. Analyzing the plant response, consistent with these conditions, the resulting peak RCS pressure is 587.4 psia. Since the Appendix G allowable pressure is 608.7 psia, there is a margin of 21.3 psi.

The most limiting heat addition transient is the restart of an RCP with the SG secondary side hotter than the RCS primary side by 50 EF. This transient will heat and pressurize the primary side very fast compared to the inadvertent activation of the pressurizer heaters or the loss of RHR cooling. The last two cases progress slowly and are not considered significant contributors as they may be interrupted by operator action. For the limiting heat injection transient and the same initial conditions as in the mass addition case, the resulting peak pressure is 551.3 psia. Since the Appendix G allowable pressure of 608.7 psia, there is a 57.4 psi margin. Therefore, the mass addition case produces only 21.3 psi of margin, it is the most limiting transient.

The above scenarios are applicable to Modes 4, 5, and 6. However, in Mode 6 with the reactor head on, the RCS depressurized, and the LTOP not available, the vessel is vented through a 1.1 in^2 opening. The 1.1 in^2 vent is large enough to accommodate the activation of a safety injection pump.

After EPU implementation the only difference regarding the LTOP is increased decay heat. However, the mass addition case involves the inadvertent startup of an RCS pump, where decay heat has no impact. Thus, the mass addition transient is not affected by the EPU. In the case of the limiting heat addition, the transient is very fast, and the increased decay heat has a negligible effect on the transient. Therefore, the mass injection transient remains limiting, and unaffected by the EPU. Since the proposed EPU has no effect upon the limiting transient for determining the LTOP setpoint, the setpoints remain unchanged.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the overpressure protection capability of the plant during low temperature operation. The review involved the acceptability of the fast neutron methodology and the acceptability of the LTOP analysis for Section 2.8.4.3. The staff finds that the fluence methodology and the fluence values are acceptable because they adhere to the guidance in RG 1.190 and the LTOP analysis remains valid after the EPU because the limiting mass addition transient is not affected by the increased decay heat.

The NRC staff concludes that the licensee has (1) adequately accounted for the effects of the proposed EPU on pressurization events and overpressure protection features and (2) demonstrated that the plant will continue to have sufficient pressure relief capacity to ensure that pressure limits are not exceeded. Based on this, the NRC staff concludes that the low temperature overpressure protection features will continue to provide adequate protection to meet GDC 15 and GDC 31 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to overpressure protection during low temperature operation.

2.8.4.5 Residual Heat Removal System

Regulatory Evaluation

The RHR system is used to cool down the RCS following shutdown. The RHR system is typically a low pressure system that takes over the shutdown cooling function when the RCS temperature is reduced. The NRC staff's review covered the effect of the proposed EPU on the functional capability of the RHR system to cool the RCS following shutdown and provide decay heat removal. The NRC's acceptance criteria are based on (1) GDC 4, insofar as it requires that SSCs important to safety be protected against dynamic effects; and (2) GDC 34, which specifies requirements for an RHR system. Specific review criteria are contained in SRP Section 5.4.7 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The Ginna RHR system is described in the UFSAR Section 5.4.5. The licensing report Section 2.8.4.4 describes the RHR system and the EPU effects on the system. The EPU increases the residual heat generated in the core during normal cooldown, refueling operations and accident conditions. The Ginna EPU licensing report Section 2.8.4.4.2.2 describes the parameters used in the EPU analysis. The staff found them acceptable since the parameters were conservative in modeling the heat load to be handled by the RHR system at EPU conditions. The licensee performed the plant cool down calculation at a core power of 1811 MWt to support the EPU. The analysis was performed to demonstrate that the RHR system continues to comply with its design basis function requirements and performance criteria for plant cooldown under EPU conditions. The licensee addressed the two train system alignment design capability in the Ginna UFSAR. The licensee also performed a cooldown analysis to support the worst-case scenario for the 10 CFR Part 50, Appendix R safe shutdown analysis. In addition, the licensee also performed an analysis to demonstrate the existing technical specification (TS) cooldown time limits continue to be met at EPU conditions. The licensee modeled the worst-case scenario assuming loss of offsite power (LOOP), one atmospheric dump valve, and one train of RHR and component cooling water available in the Appendix R cooldown scenario at EPU conditions. The results demonstrated the plant will achieve cold shutdown within the 72 hours time limit. The licensee also addressed mid-loop operation in licensing report Section 2.8.7.3.1 and demonstrated having processes in place that preclude loss of decay heat removal during non-power operations, consistent with Ginna's analysis of record. The EPU activities do not add any new components nor do they introduce any new functions for existing components of the RHR system. Therefore, the licensee continues to meet the regulatory requirements as stated in the UFSAR Section 5.4.5.

Conclusion

The NRC staff reviewed the licensee's analyses related to the effects of the proposed EPU on the RHR system. The NRC staff concluded that the licensee adequately accounted for the effects of the proposed EPU on the system and demonstrated that the RHR system will maintain its ability to cool the RCS following shutdown and provide decay heat removal. Based on this, the NRC staff concludes that the RHR system will continue to meet the requirements of GDCs 4 and 34 as stated in the UFSAR following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the RHR system.

2.8.5 Accident and Transient Analyses

2.8.5.1 Increase in Heat Removal by the Secondary System

2.8.5.1.1 Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve

Regulatory Evaluation

Excessive heat removal causes a decrease in moderator temperature that increases core reactivity and can lead to a power level increase and a decrease in shutdown margin. Any unplanned power level increase may result in fuel damage or excessive reactor system pressure. Reactor protection and safety systems are actuated to mitigate the transient.

The NRC staff's review covered (1) postulated initial core and reactor conditions, (2) methods of thermal and hydraulic analyses, (3) the sequence of events, (4) assumed reactions of reactor system components, (5) functional and operational characteristics of the RPS, (6) operator actions, and (7) the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations including AOOs; (2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; (3) GDC 20, insofar as it requires that the reactor protection system be designed to initiate automatically the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded during any condition of normal operation, including AOOs; and (4) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.1.1-4 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

Decrease in feedwater temperature, increase in feedwater flow, increase in steam flow, and inadvertent opening of a SG relief or safety valve are classified as ANS Condition II events (Reference 34), faults of moderate frequency. These faults, at worst, result in a reactor trip with the plant being capable of returning to operation after corrective action.

The licensing report presents the results of an analysis of the increase in feedwater flow event. Since the increase in feedwater flow is the limiting event, the other transients were evaluated by the licensee.

An increase in feedwater flow event can be caused by a flow control failure that drives a main feedwater regulating valve (MFRV) to its fully open position. If the flow control failure is the failure of a processing controller in the advanced digital feedwater control system, then it is /////possible to simultaneously open the atmospheric relief valve(s) (ARV(s)), the MFRV(s), and the main feedwater bypass valve(s). Therefore, the licensee has analyzed cases that postulate the spurious opening of these valves.

Since a credible steam line break can be defined as the spurious opening of an SG ARV, an increase in feedwater flow (or feedwater system malfunction) coincident with the spurious opening of an ARV (credible steamline break) would cause a more severe cooldown than a credible steamline break event. The credible steam line break is not analyzed, since it's bounded by the increase in feedwater flow event which includes the coincident opening of an ARV.

The feedwater system malfunction transient was analyzed with the RETRAN (Reference 32) computer code. The licensee's current analysis of record (AOR) is the product of LOFTRAN (Reference 29) simulations. Both codes have been accepted by the NRC. Transient DNBR evaluations were conducted using the WRB-1 DNB correlation (for hot full power (HFP) cases) and the W-3 correlation (for hot zero power (HZP) cases), and the VIPRE code (Reference 35). VIPRE is another NRC-accepted code that is incorporated into the Ginna licensing basis as part of this amendment application.

Since the increase in feedwater flow event is an ANS Condition II event, it is necessary to show that no fuel clad damage is predicted. This is inferred from analysis results that indicate the minimum DNBR remains above the safety analysis limit (SAL) throughout the transient. The minimum DNBR yielded by the HFP analyses is 1.60, which is well above the DNBR SAL of 1.38. HZP cases were not analyzed, since the cooldown caused by the increase of feedwater flow event is exceeded by the cooldown resulting from a HZP steam system piping failure (licensing report Section 2.8.5.1.2). Comparison between the increase of feedwater flow event, an ANS Condition II event, and a steam system piping failure, ANS Condition IV event, is permissible since both events are judged according to the same, ANS Condition II, acceptance criteria.

The decrease in feedwater temperature event, which can be caused by the opening of a condensate bypass valve diverting flow around the low-pressure feedwater heaters, is not analyzed. This event is bounded by the HFP steam system piping failure (licensing report Section 2.8.5.1.2).

The increase in steam flow (or excessive load increase) incident is defined as a rapid increase in steam flow that causes a mismatch between the reactor core power and the SG load demand.

The reactor control system is designed to accommodate a 10% step-load increase or a 5% per minute ramp-load increase in the range of 15 to 100% of full power. Any loading rate in excess of these values can cause a reactor trip actuated by the RPS. Greater increases in steam load are analyzed as steam line rupture events (licensing report Section 2.8.5.1.2).

The increase in steam flow is evaluated for a step-load increase of 10% steam flow from 100% of NSSS thermal power (1817 MWt). Since the plant is designed to tolerate a 10% step-load increase in steam flow, an analysis was not deemed to be necessary. Instead, an evaluation was performed by Westinghouse, that consisted of a comparison of Ginna statepoints against a body of statepoints from a compilation of excessive load increase analyses performed for various Westinghouse 2-loop, 3-loop and 4-loop plants. The statepoints are normalized (i.e., expressed as change from nominal) so statepoints from plants of various operating parameters could be compared. The statepoints were then considered in terms of the core thermal limits (licensing report Figure 2.8.5.0-1) to ensure that the DNBR limit was not violated.

This method has been used in other amendment applications in the past. It may be considered analogous to the approximation of DNBR that is calculated by LOFTRAN and RETRAN, based upon derivative relationships in the core limit curves. The results of the evaluation indicated that the DNBR SAL is not violated (i.e., min DNBR > 1.38).

Conclusion

The NRC staff has reviewed the licensee's analyses of the excess heat removal events described above and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of these events. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, 20, and 26 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the excess heat removal events described above.

2.8.5.1.2 Steam System Piping Failures Inside and Outside Containment

Regulatory Evaluation

The steam release resulting from a rupture of a main steam pipe will result in an increase in steam flow, a reduction of coolant temperature and pressure, and an increase in core reactivity. The core reactivity increase may cause a power level increase and a decrease in shutdown margin. Reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered (1) postulated initial core and reactor conditions; (2) methods of thermal and hydraulic analyses; (3) the sequence of events; (4) assumed responses of the reactor coolant and auxiliary systems; (5) functional and operational characteristics of the RPS; (6) operator actions; (7) core power excursion due to power demand created by excessive steam flow; (8) variables influencing neutronics; and (9) the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; (2) GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other RV internals so as to significantly impair the capability to cool the core; (3) GDC 31, insofar as it requires that the RCPB be designed with sufficient margin to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; and (4) GDC 35, insofar as it requires the reactor cooling system and associated auxiliaries be designed to provide abundant emergency core cooling. Specific review criteria are contained in SRP Section 15.1.5 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

A return to power following a steam pipe rupture is a concern primarily because of the high power peaking factors that would develop when the most reactive rod cluster control assembly is assumed to be stuck in its fully withdrawn position. The core is shut down by the RPS and safety systems by tripping the rods and injecting boric acid into the RCS.

The rupture of a major steam line is the most-limiting of the cooldown transients. Analyses for the steamline break initiated from an HFP condition, and also from a HZP condition, are presented in the licensing report. The maximum break size is 1.4 ft^2, the effective flow area of the integral flow restrictor inside each SG steam outlet nozzle.

Although steam system piping failures are categorized as ANS Condition IV events (Reference 34), the results of these analyses are conservatively judged against the more stringent Condition II acceptance criteria. Condition II acceptance criteria require that fuel clad integrity be maintained by demonstrating that the minimum DNBR remains above the DNBR SAL throughout the transient.

The licensee used the RETRAN (Reference 32) computer code to simulate the NSSS response to the main steam line break (MSLB) transient and to provide dynamic core conditions to the VIPRE (Reference 35) thermal-hydraulic code. The VIPRE code, employing the WRB-1 correlation for the HFP cases and the W-3 correlation for the HZP cases (since local conditions were outside the WRB-1 applicability range), was used to calculate the DNBR at the limiting time during the transient. These computer models and methods have been previously reviewed and approved by the staff for the MSLB analysis and their application is consistent with the proposed EPU conditions.

a. Steam System Piping Failure at Hot Zero-Power (HZP) Analysis

For the steam system piping failure at HZP analysis, it is assumed that there is no decay heat present. This produces more severe consequences than would be expected of the post-trip portion of the HFP case, since decay heat retards the cooldown and thus reduces the return to power. The RETRAN and VIPRE codes were used, with the STDP, to determine the minimum DNBR. The resulting minimum DNBR is 2.58, which exceeds the applicable DNBR SAL of 1.566.

The HZP steam line break analysis was performed for the maximum break size (1.4 ft^2) and for a break size just large enough to generate a steamline isolation signal, based on the coincidence of high steam flow in both loops, a safety injection signal, and low T_{avg}. The latter analysis was performed with no credit for execution of automatic steam line isolation. After 10 minutes it was assumed that operators would manually close the MSIVs to terminate the event. The results of this analysis were bounded by the 1.4 ft^2 HZP steam line break analysis. This break size, therefore, determines the largest break size for which operator action (in 10 minutes) is sufficient to provide protection, and establishes an acceptable basis for the steam line isolation setpoint. Larger break sizes would be bounded by the maximum break size HZP steamline break analysis.

Manual steamline isolation in 10 minutes is justified in the following manner. The operator would have adequate indications to identify transient as a steamline break. Since safety injection would be actuated on a low pressurizer pressure signal, the operator would enter emergency operating procedure (EOP) E-0 (which is entered on either a reactor trip or the initiation of safety injection) (Reference 26). Implementation of the E-0 procedure provides an initial opportunity to close the MSIV's at step 8, wherein a check of conditions requiring steamline isolation is performed. Time studies show that, when performing E-0 on the simulator, step 8 is typically reached by the operators within about 3.8 minutes. Finally, after step 8, the operator is directed by E-0 to close the MSIVs at step 20 if the reactor coolant system cooldown has not been terminated. Time studies on the simulator have shown that operators reach this step within about 9.5 minutes.

During an audit (Reference 24), the NRC staff reviewed the Westinghouse engineering calculations supporting this event. As part of the audit, the staff read the safety analysis guidelines, used by Westinghouse analysts, and verified the transfer of transient statepoints between RETRAN and VIPRE calculations. Based upon the input parameters, assumptions, and modeling techniques, the staff finds the post-trip MSLB transient simulation and the identification of the limiting cases acceptable. The limiting post-trip MSLB cases demonstrate that the calculated minimum DNBR remains above the DNB SAL of 1.566, ensuring that fuel rod failure does not occur.

b. Steam System Piping Failure at Hot Full-Power (HFP) Analysis

The current licensing basis for Ginna does not include a specific assessment of the pre-trip power excursion portion of the MSLB event. The Ginna UFSAR focuses solely on the post-trip return-to-power event.

For the steam system piping failure at HFP analysis, minimum DNBRs are calculated for typical and thimble cells of the 422V+ and OFA fuel designs. For each fuel cell type and design, there is a corresponding DNBR SAL. The RETRAN and VIPRE codes were used, with the RTDP, to determine the minimum DNBR. The minimum DNBR, from the analysis results (1.39 for 422V+ fuel) exceeds the maximum of the DNBR SALs (1.38 for 422V+ fuel). Therefore, the Condition II fuel cladding integrity acceptance criterion is met.

The event is analyzed over a spectrum of break sizes in order to identify the most limiting overpower condition, which is typically the largest break to produce a reactor trip on overpower delta temperature (OPΔT). The limiting break size is the maximum break size (1.4 ft^2). The peak linear heat generation rate is 22.67 kW/ft, just under the limit of 22.7 kW/ft.

The HFP transient analysis is ended at the time of reactor trip, since the post-trip portion of the HFP steam line break is bounded by HZP analyses.

Since the steamline break analysis causes a cooldown and depressurization of the RCPB, and the Ginna safety injection system is not capable of repressurizing the RCPB to pressures beyond about 1500 psia, the staff did not consider the requirement of the RCPB being designed with sufficient margin to assure that, under the specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized. See licensing report Section 2.8.4.3 for a discussion of cold overpressurization.

Conclusion

The NRC staff has reviewed and audited (Reference 24) the licensee’s analyses of steam system piping failure events and concludes that the licensee’s analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to assure that the ability to insert control rods is maintained, and abundant core cooling will be provided. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 27, 28, 31, and 35 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to steam system piping failures.

2.8.5.2 Decrease in Heat Removal By the Secondary System

2.8.5.2.1 Loss of External Load, Turbine Trip, Loss of Condenser Vacuum, and Steam Pressure Regulatory Failure

Regulatory Evaluation

A number of initiating events may result in unplanned decreases in heat removal by the secondary system. These events result in a sudden reduction in steam flow and, consequently, result in pressurization events. Reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered the sequence of events, the analytical models used for analyses, the values of parameters used in the analytical models, and the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; and (3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.2.1-5 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The loss of load event (UFSAR Section 15.2.2) can result from either a loss of-external-electrical load or from a turbine trip. Although a loss-of-external-electrical load can be caused by a problem in the electrical network, offsite power would remain available, to drive the RCPs.

Ginna is designed to accept a 50% rapid decrease (200% per minute) in electrical load while operating at full power, or a complete loss of load while operating below 50% power without actuating a reactor trip with all NSSS control systems in automatic (licensing report Section 2.5.5.3, "Turbine Bypass"). A 50% load loss is handled by the steam dump system, the rod control system, and the pressurizer. A complete loss of load, occurring at full power, would require an automatic reactor trip.

A trip of the turbine generator at full power, for example, would cause a complete loss of load and generate a reactor trip signal from either the turbine auto-stop oil pressure or a closure of the turbine stop valves. Automatic control systems, such as the steam dump, automatic rod control, and pressurizer pressure control systems maintain reactor coolant temperature and pressure within their operating ranges. However, operation of these systems are not normally credited in accident analyses. The licensing report analyses consider the complete loss-of-load from full power without direct reactor trip in order to demonstrate the adequacy of the safety-related pressure-relieving devices and core protection margin, under the proposed EPU conditions.

Three cases were analyzed for a total loss of load from EPU full-power conditions:

1. DNB case: pressure is kept conservatively low by crediting automatic pressure control, in order to verify that adequate thermal margin is maintained. The acceptance criterion is to maintain DNBR at values greater than the DNBR SAL (1.38). The DNBR case was

analyzed using the RTDP. Therefore, RCS temperature and pressure were assumed to be at their nominal values consistent with steady-state, EPU full-power operation. Minimum measured flow was assumed.

2. Main steam system (MSS) pressure case: the reactor trip was conservatively delayed (i.e., trip occurs on OTΔT, not high pressurizer pressure) by crediting automatic pressure control and primary to secondary heat transfer is maximized by assuming minimum SGTP and no SG tube fouling to obtain a high peak MSS pressure. The acceptance criterion is to limit peak MSS pressure to less than 110% of the secondary side design pressure. The STDP was employed (i.e., initial uncertainties for reactor coolant flow, temperature, and pressure were applied in the conservative direction to obtain the initial plant conditions for the transient).

3. RCS pressure case: the RCS pressure is maximized by not crediting automatic pressure control. The acceptance criterion is to limit peak RCS to less than 110% of the primary side design pressure. The STDP was employed.

Only the OTΔT, high-pressurizer pressure, and OPΔT reactor trip signals are credited. Reactor trips from high pressurizer level and turbine trip were not credited.

The analyses were performed using the RETRAN (Reference 32) computer code, which models the core neutron kinetics, RCS, pressurizer, pressurizer PORVs and sprays, SGs, main steam safety valves, and the auxiliary feedwater (AFW) system. RETRAN also approximates DNBR values, based upon the Ginna core thermal limits.

The analysis results for Case 1 (DNBR case) indicate that the reactor was tripped from an OTΔT signal. The minimum DNBR, as calculated by RETRAN, was 1.61, well above the SAL. Also, the pressurizer does not become water-solid, demonstrating that this event could not develop into a more serious plant condition.

The analysis results for Case 2 (MSS pressure case) indicate that the reactor was also tripped from an OTΔT signal. The secondary side pressure was limited by the opening of the MSSVs. The maximum steam pressure, as calculated by RETRAN, was 1208 psia, which was slightly below the limit (110% of the MSS design pressure).

The analysis results for Case 3 (RCS pressure case) indicate that the reactor was tripped from the high-pressurizer pressure reactor trip signal. The RCS pressure was limited by the opening of the pressurizer safety valves. The maximum RCS pressure, as calculated by RETRAN, was 2746.8 psia, which was slightly below the limit (110% of the RCS design pressure).

The turbine trip event (i.e., closure of the turbine stop valves) and the loss-of-condenser vacuum event are bounded by the analyses performed for the loss of external electrical load event. If condenser vacuum is lost, the turbine is tripped and, therefore, the event is similar to the turbine trip event.

Based upon the input parameters, assumptions, and modeling techniques described in licensing report Section 2.8.5.2.1, the staff finds the Ginna loss of load transient simulations and the identification of the limiting cases acceptable. The licensee provided reasonable assurance that all of the acceptance criteria continue to be met at the proposed EPU conditions.

Conclusion

The NRC staff has reviewed the licensee's analyses of the decrease in heat removal events described above and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of these events. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the events stated.

2.8.5.2.2 Loss of Nonemergency AC Power to the Station Auxiliaries

Regulatory Evaluation

The loss of nonemergency ac power is assumed to result in the loss of all power to the station auxiliaries and the simultaneous tripping of all reactor coolant pumps. This causes a flow coastdown as well as a decrease in heat removal by the secondary system, a turbine trip, an increase in pressure and temperature of the coolant, and a reactor trip. Reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered (1) the sequence of events, (2) the analytical model used for analyses, (3) the values of parameters used in the analytical model, and (4) the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; and (3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.2.6 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

Since power is cut off from the reactor coolant pumps, the coolant flow that is necessary for core cooling and removal of residual heat is maintained by natural circulation in the reactor coolant loops, which is driven by the heat sink provided by the AFW system.

The loss of nonemergency ac power event is classified as an ANS Condition II event (Reference 34). The analysis acceptance criteria require that DNBR remain above the SAL, that pressure in the RCS and MSS be limited to levels below 110% of their respective design pressures, and that the pressurizer does not become water-solid.

This transient is analyzed using the RETRAN computer code (Reference 32). The loss of nonemergency ac power transient resembles the complete loss of reactor coolant flow event (licensing report Section 2.8.5.3.1), and the loss of normal feedwater (LONF) event (licensing report Section 2.8.5.2.3). The principal acceptance criterion for the complete loss of reactor coolant flow event is that DNBR remain above the SAL. Therefore, analysis of this event is ended after the minimum DNBR is reached, shortly after the reactor is tripped. Analyses of the loss of nonemergency ac power and LONF events are concerned with decay heat removal. Therefore, these analyses are longer-term, and focus upon the analysis acceptance criteria that pressure in the RCS and MSS be limited to levels below 110% of their respective design pressures, and that the pressurizer does not become water-solid. All three events would be affected by the proposed EPU.

The RETRAN analysis results indicate that natural circulation and AFW flow are capable of providing adequate core decay heat removal following a reactor trip and RCP coastdown. The analysis is conservative, since the reactor trip is not assumed to occur on the loss of power or the loss of RCP flow. Reactor trip is assumed to occur much later, on low-low SG water level. (The Ginna main feedwater pumps are 4500-hp, 1800 rpm electric motor-driven pumps.) The results also show that the loss of nonemergency ac power event could not develop into a more serious event. The calculated peak pressurizer water volume is 636 ft^3, which is not enough to fill Ginna's pressurizer (800 ft^3). Therefore, there would be no water discharge through the pressurizer relief or safety valves. The results also show that RCS and MSS pressures remain below the applicable design limits throughout the transient.

The NRC staff reviewed the licensee's analysis of the loss of AC power to plant auxiliaries and concludes that the licensee's analysis was performed using an acceptable analytical model, as stated above. The staff finds the licensee demonstrated that the reactor protection and safety systems will continue to ensure that the specified fuel design limits are not exceeded, the peak primary and secondary system pressures are not exceeded, and a more serious plant condition is precluded. The staff concludes that the plant will continue to meet the regulatory requirements following implementation of the proposed power uprate. Therefore, the staff finds the proposed power uprate acceptable with respect to the loss of AC power to the plant auxiliaries.

Conclusion

The NRC staff has reviewed the licensee's analyses of the loss of nonemergency ac power to station auxiliaries event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the loss of nonemergency ac power to station auxiliaries event.

2.8.5.2.3 Loss of Normal Feedwater Flow

Regulatory Evaluation

A loss of normal feedwater flow could occur from pump failures, valve malfunctions, or a LOOP. Loss of feedwater flow results in an increase in reactor coolant temperature and pressure that eventually requires a reactor trip to prevent fuel damage. Decay heat must be transferred from fuel following a loss of normal feedwater flow. Reactor protection and safety systems are actuated to provide this function and mitigate other aspects of the transient. The NRC staff's review covered (1) the sequence of events, (2) the analytical model used for analyses, (3) the values of parameters used in the analytical model, and (4) the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with margin sufficient to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; and (3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.2.7 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The loss of normal feedwater flow event is classified as an ANS Condition II event (Reference 34). The analysis acceptance criteria require that DNBR remain above the SAL, that pressure in the RCS and MSS be limited to levels below 110% of their respective design pressures, and that the pressurizer does not become water-solid.

The licensee used the RETRAN computer code (Reference 32) to analyze this event. The analysis is performed to show that following a loss of normal feedwater, the AFW system is capable of removing the stored energy, residual decay heat, and RCP heat. The loss of feedwater event is bounded by the loss of load/turbine trip event analysis (licensing report Section 2.8.5.2.1) for overpressurization, since the loss of heat sink, resulting from a turbine trip, is more severe than that of the loss of feedwater event. In performing its analysis, the licensee used conservative assumptions to maximize the time to reactor trip and to minimize the energy removal capability of the AFW system.

The analysis considers both ends of the full power vessel average temperature (T_{avg}) window (564.6 EF to 576 EF), with a temperature uncertainty of +/- 4 EF. The LONF case that yields the highest pressurizer water volume is based upon the lowest assumed value for nominal T_{avg} (i.e., 564.6 EF - 4 EF), and the highest assumed nominal RCS pressure (i.e., 2250 psia + 60 psi). SGTP levels of both 0 and 10% were also analyzed. The pressurizer spray, PORVs, and heaters were assumed to be operable to maximize the pressurizer water volume. For the EPU, the licensee has set a new pressurizer level program for operation at the low end of the temperature window. For a full power T_{avg} of 564.6 EF, the nominal pressurizer level is reduced to 44.3% narrow range span (NRS) from the current programmed level of 54% NRS. Thus, there is a larger steam bubble in the pressurizer, to accommodate the insurge caused by the LONF.

The reactor trip occurs in about 1 minute, on low-low SG water level. AFW flow, from two motor-driven AFW pumps, is actuated about 1 minute later. The worst single failure modeled in the analysis is the failure of the turbine-driven AFW pump to start. The results of the analysis show that the pressurizer does not reach a water-solid condition. The calculated long-term peak pressurizer water volume occurs almost 15 minutes into the event, and reaches 537 ft^3, which is less than the 800 ft^3 needed to fill the pressurizer. The analysis results also show that the peak RCS and MSS pressures remain below their respective 110% of design pressure limits throughout the transient. With respect to DNB, the LONF accident is bounded by the loss of load accident, that generates a more severe power mismatch between the primary and secondary systems.

The NRC staff reviewed the licensee's analysis for the LONF flow transient and concludes that the licensee's analysis has adequately accounted for operation of the plant at the proposed power level and was performed using an acceptable analytical model. The staff finds the licensee demonstrated that the ANS Condition II acceptance criteria are satisfied. The pressurizer would not become water-solid during this transient and the flow from two motor-driven AFW pumps is sufficient to dissipate core residual heat, stored energy, and RCP heat such that water would not be discharged through the pressurizer relief or safety valves. The staff concludes that the plant will continue to meet the regulatory requirements following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the loss of normal feedwater flow event.

Conclusion

The NRC staff has reviewed the licensee's analyses of the loss of normal feedwater flow event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of the loss of normal feedwater flow. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the loss of normal feedwater flow event.

2.8.5.2.4 Feedwater System Pipe Breaks Inside and Outside Containment

Regulatory Evaluation

A major feedwater line break (FLB), an ANS Condition IV event (Reference 34), is defined as a break in a feedwater line large enough to prevent the addition of sufficient feedwater to the SGs to maintain shell-side fluid inventory. Depending upon the size and location of the break and the plant operating conditions at the time of the break, the break could cause either an RCS cooldown (by excessive energy discharge through the break) or an RCS heatup (by reducing feedwater flow to the affected SG). In either case, reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered (1) postulated initial core and reactor conditions, (2) the methods of thermal and hydraulic analyses, (3) the sequence of events, (4) the assumed response of the reactor coolant and auxiliary systems, (5) the functional and operational characteristics of the RPS, (6) operator actions, and (7) the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; (2) GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other RV internals so as to significantly impair the capability to cool the core; (3) GDC 31, insofar as it requires that the RCPB be designed with sufficient margin to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; and (4) GDC 35, insofar as it requires the reactor cooling system and associated auxiliaries be designed to provide abundant emergency core cooling. Specific review criteria are contained in SRP Section 15.2.8 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

FLB cases that can cause an RCS cooldown were covered by the analysis of another ANS Condition IV event, the steamline break. Therefore, the FLB was evaluated as one of the events that can cause an RCS heatup. Analysis of this event demonstrates the ability of the AFW system to remove core decay heat and thereby assure that the core remains in a coolable geometry. It can be inferred that the core remains covered with water (and coolable) if the hot and cold leg temperatures remain subcooled until the AFW system heat removal rate exceeds the RCS heat generation rate (mainly from decay heat). The staff's review focused on the NSSS response to the FLB event to provide reasonable assurance that the AFW system, in combination with the reactor protection and safety systems, have the capacity to remove decay heat, to prevent overpressurization of the RCS, and prevent uncovery of the core. Specific review criteria are found in SRP Section 15.2.8.

The licensee used the RETRAN (Reference 32) computer code to analyze the FLB event. The AOR for the FLB event is the product of LOFTRAN (Reference 29) analyses. Both codes have been reviewed and accepted by the staff for FLB analyses. The analyses model a simultaneous loss of main feedwater to all SGs and subsequent reverse blowdown of the faulted SG.

The analysis acceptance criterion, applied to the FLB event, is the requirement that there is no boiling in the hot legs before decay heat decrease to below the heat removal capacity of the AFW system. Meeting this criterion provides reasonable assurance that the core will always remain covered and in a coolable geometry.

In the licensee's analyses, the location of the break in the feedwater piping was assumed to be between the feedline check valve and the SG. A break upstream of the feedline check valve would not result in a blowdown from the SG. Instead, the SG would experience a transient similar to the loss of feedwater event (licensing report Section 2.8.5.2.3).

The licensing report contains analyses for FLBs of 1.418 ft^2. This break size corresponds to the diameter of the feedwater inlet nozzle, excluding the sleeve (Reference 26). The results of a sensitivity study indicate that the 1.418 ft^2 break would yield a smaller margin to hot leg boiling than would a 1.12 ft^2 break. This is conservative since the 1.12 ft^2 break area corresponds to the feedwater nozzle sleeve inside diameter, which is the largest effective break size that the generator could experience.

Ginna analyzed eight cases, to identify the limiting FLB scenario.

(1) Maximum reactivity feedback, with offsite power, 1.418 ft^2 break outside intermediate building
(2) Maximum reactivity feedback, with offsite power, 1.418 ft^2 break inside intermediate building
(3) Maximum reactivity feedback, without offsite power, 1.418 ft^2 break outside intermediate building
(4) Maximum reactivity feedback, without offsite power, 1.418 ft^2 break inside intermediate building
(5) Minimum reactivity feedback, with offsite power, 1.418 ft^2 break outside intermediate building
(6) Minimum reactivity feedback, with offsite power, 1.418 ft^2 break inside intermediate building
(7) Minimum reactivity feedback, without offsite power, 1.418 ft^2 break outside intermediate building
(8) Minimum reactivity feedback, without offsite power, 1.418 ft^2 break inside intermediate building

AFW is relied upon to remove decay heat following an FLB. Since the turbine-driven AFW pump is connected to both SGs, it is assumed that all of its flow would spill out through the broken feedline. A single failure, therefore, would be assumed in either of the two motor-driven AFW pumps. If the failure is assumed to occur in the AFW pump that is aligned to the faulted SG (i.e., in the “FLB outside intermediate building” cases), then 195 gpm of AFW flow would be delivered to the intact SG, beginning 60 seconds after receipt of the SG low-low water level signal. If the failure is assumed to occur in the AFW pump that is aligned to the intact SG (i.e., in the “FLB inside intermediate building” cases), then 235 gpm of AFW flow would be delivered to the intact SG, beginning 870 seconds after receipt of the SG low-low water level signal.

For the “FLB inside intermediate building” cases, the EOPs require the operator to realign the AFW system (i.e., align the turbine-driven pump to the intact SG), or put the standby AFW system into operation within 870 seconds (Reference 26) after the receipt of the low-low SG water level signal. The licensee is required to transition from the E-0 procedure to the FRH-1 procedure during a feedline break accident. The licensee has demonstrated in the simulator that it takes the operators a maximum of 7 minutes to transition from E-0 to FRH-1. The licensee has re-written FRH-1 to commence the initiation of standby AFW or the re-alignment of AFW at step 4 vice a later step. The licensee has verified that it takes less than a maximum of 7 minutes for the operators to reach step 4 of FRH-1 and commence standby AFW or re-align AFW in the current simulator. However, the simulator has not been fully reconfigured to account for the power uprated conditions at this time. The licensee has also confirmed that the 870 second assumption will continue to be valid under the new procedures after the simulator is reconfigured to account for the EPU conditions. (Reference 58).

The low-low SG water level reactor trip signal is based upon a detailed Ginna SG model that was developed using the methods described in Section 3 of WCAP-14882-S1-P-A (Reference 59). These methods, which employ the NOTRUMP (Reference 60) SG thermal-hydraulic computer code to calculate secondary side SG water masses, were used to determine the amount of water mass in the SG at the time a low SG level reactor trip is reached. The SG shell side mass is then used to define the reactor trip condition in RETRAN. This method is also used to determine the shell side mass equivalents for feedring and tube uncovery in the faulted Ginna SG.

The limiting FLB scenario, as determined by the subcooling margin available in the RCS hot legs, is Case (6), the 1.418 ft^2 feedline break inside the intermediate building, with offsite power available and with minimum reactivity feedback. The minimum subcooling margin, in the RCS hot legs, is 2 EF. However, during its review of an FLB analysis in another amendment application (Reference 61), the NRC staff had a question concerning the Westinghouse methodology that identifies the limiting scenario as the maximum break size. Contrary to the FLB methodology in WCAP-9230 (Reference 62), the largest possible break size may not yield the most conservative results. In response, an issue report was entered into the Westinghouse Corrective Action Process (CAP) to investigate the effects of varying break size on the NOTRUMP Low SG Level trip mass, the break flow enthalpy, and the overall RETRAN simulation.

As part of that review (Reference 61), the NRC staff considered a sensitivity study on break discharge quality that demonstrated the existence of a margin to hot leg saturation even when FLB break flow was assumed to be saturated water. The staff will follow this issue and the Westinghouse CAP, previously mentioned, on a generic basis. Since the Ginna FLB analysis to support the EPU shows sufficient margin to hot-leg saturation when the discharge quality is assumed to be saturated water, the NRC staff finds that this issue does not need to be addressed, at this time, to support the Ginna EPU program.

The FLB analysis employs a number of conservative assumptions. The pressurizer PORVs are assumed to operate, as designed, to limit the RCS pressure, and thereby limit the hot leg saturation temperature. The staff agrees that for minimizing margin to hot leg saturation, PORV operation is conservative. The staff also considers the FLB event would not yield a peak RCS pressure that would exceed the peak pressure produced by the loss of load event. Therefore, it is not necessary to calculate the peak RCS and MSS pressures for the FLB events.

Maintenance of a steam bubble in the pressurizer is not required for Condition IV events, like the FLB. The analysis results indicate that the Ginna pressurizer becomes water-solid, more than 1,000 seconds after the FLB occurs. The PORVs open and relieve water, which limits the RCS pressure and hot leg saturation temperature. The time scale implies there would be ample time available for corrective actions by the operator. If the PORVs were not available, the safety valves would open, and limit the RCS pressure to less than 110% of RCS design pressure. In this case, there would be more subcooling margin available, since the RCS pressure would be higher.

Based upon the input parameters, assumptions, and modeling techniques described in the licensing report, and the licensee's responses to the staff's RAIs, the staff finds the Ginna FLB transient simulations and the identification of the limiting cases acceptable. The licensee provided reasonable assurance that all of the acceptance criteria continue to be met at the proposed EPU conditions. The Ginna AFW system capacity was shown to be adequate to remove decay heat, to prevent overpressurizing the RCS, and to prevent uncovering the reactor core.

Conclusion

The staff reviewed the FLB analyses and concluded that (1) they were performed using acceptable analytical models, and (2) they adequately account for operation of the plant at the proposed EPU conditions. The staff further concluded that the licensee demonstrated that the reactor protection and safety systems will continue to assure that the ability to insert control rods is maintained, the RCPB pressure limits will not be exceeded, and adequate core cooling will be provided. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 27, 28, 31, and 35 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to feedwater system pipe breaks.

2.8.5.3 Decrease in Reactor Coolant System Flow

2.8.5.3.1 Loss of Forced Reactor Coolant Flow

Regulatory Evaluation

A decrease in reactor coolant flow occurring while the plant is at power could result in a degradation of core heat transfer. An increase in fuel temperature and accompanying fuel damage could then result if SAFDLs are exceeded during the transient. Reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered (1) the postulated initial core and reactor conditions, (2) the methods of thermal and hydraulic analyses, (3) the sequence of events, (4) assumed reactions of reactor systems components, (5) the functional and operational characteristics of the RPS, (6) operator actions, and (7) the results of the transient analyses. The NRC’s acceptance criteria are based on (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with margin sufficient to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; and (3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.3.1-2 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The loss of forced reactor coolant flow transient for Ginna was addressed in UFSAR Section 15.3 and the EPU licensing report Section 2.8.5.3. A complete loss of forced reactor coolant flow event is classified as an ANS Condition III event (Reference 34). However, the licensee has conservatively applied Condition II acceptance criteria for this event’s analysis. The complete loss of forced reactor coolant flow can cause an increase in the reactor coolant temperature, and RCS pressure.

The complete loss of forced reactor coolant flow may result from the loss of both RCPs, or from a decay in grid frequency. Both cases were analyzed. In addition, the licensee analyzed the loss of one RCP, a partial loss of flow event, and found that it is bounded by the complete loss of flow events. The partial loss of flow case was analyzed at 35% power. The results indicated that the DNBR SAL is satisfied for single loop operation. These results also demonstrate the acceptability of 35% as the P-8 permissive setpoint for the EPU. (The P-8 permissive setpoint defines the highest steady-state power level at which the reactor can operate with one RCS loop.)

The complete loss of flow event is analyzed using the RTDP (Reference 37). Initial core power was assumed to be at its nominal value consistent with steady-state, full power operation. RCS pressure and RCS vessel average temperature were also assumed to be at their nominal values. Uncertainties in the initial conditions were included in the DNBR limit value as described in the RTDP.

The RETRAN (Reference 32) computer code was used to calculate the RCS loop and core flows during the transient, to determine the time of reactor trip based upon the calculated RCS flows, calculate the nuclear power transient, and the primary-system pressure and temperature transients. The VIPRE (Reference 35) computer code was then used to calculate the heat flux and DNBR transients based on the nuclear power and RCS temperature (enthalpy), pressure, and core flow from RETRAN.

The complete loss of flow event analysis results confirmed that the minimum DNBR values were greater than the SAL value of 1.38 at EPU conditions, and that the peak RCS pressure remained below 110% of its design limit at all times. The minimum DNBR that resulted from the analyses of the loss of flow, partial loss of flow, and underfrequency cases is 1.385 (for a typical 422V+ fuel assembly during the underfrequency event). The staff finds that licensee's analyses demonstrate that the acceptance criteria will continue to be met, for the loss of reactor coolant flow events that may occur under the proposed EPU conditions.

Conclusion

The NRC staff reviewed the licensee's analyses of the decrease in reactor coolant flow event and concluded that the licensee's analyses adequately accounted for operation of the plant at the proposed EPU level and were performed using acceptable analytical models. The NRC staff further concluded that the licensee demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the NRC staff concluded that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the decrease in reactor coolant flow event.

2.8.5.3.2 Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break

Regulatory Evaluation

The events postulated are an instantaneous seizure of the rotor or break of the shaft of an RCP. Flow through the affected loop is rapidly reduced, leading to a reactor and turbine trip. The sudden decrease in core coolant flow while the reactor is at power results in a degradation of core heat transfer, which could result in fuel damage. The initial rate of reduction of coolant flow is greater for the rotor seizure event. However, the shaft break event permits a greater reverse flow through the affected loop later during the transient and, therefore, results in a lower core flow rate at that time. In either case, reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered (1) the postulated initial and long-term core and reactor conditions, (2) the methods of thermal and hydraulic analyses, (3) the sequence of events, (4) the assumed reactions of reactor system components, (5) the functional and operational characteristics of the RPS, (6) operator actions, and (7) the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained and (2) GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other RV internals so as to significantly impair the capability to cool the core. Specific review criteria are contained in SRP Section 15.3.3-4 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The Ginna RCP rotor seizure and RCP shaft break accident was addressed in the UFSAR Section 15.3 and the EPU licensing report Section 2.8.5.3.2. This event is classified as an ANS Condition IV event (Reference 34). The specific analysis acceptance criteria applied by Ginna for this event are (1) the peak clad temperature must not exceed 2700 EF (and the maximum zirconium-water reaction must remain below 16%), and (2) peak RCS and MSS pressures must not exceed 120% of their respective design pressures. Loss of external electrical load, turbine trip, and loss of condenser vacuum (licensing report Section 2.8.5.2.1) produced higher MSS pressures than did this event.

The licensee used the RETRAN (Reference 32) and VIPRE (Reference 35) computer codes to analyze this accident at EPU conditions. The licensee performed the analyses using the RETRAN computer code to calculate the loop and core flow transients, the time of reactor trip based on the calculated flows, the nuclear power transient, and the primary system pressure and temperature transients. The VIPRE computer code was then used to calculate the peak cladding temperature using the input from RETRAN. The licensee proposed to change the rod drop time in the AOR. The staff found this change acceptable since the new value is still conservative, is within the TS limit of 1.8 seconds, and the acceptance criteria continue to be met. The results of the analyses show that the peak RCS pressure was 2782 psia, less than the acceptance criterion of 2997 psia. The peak cladding temperature (1924.6 EF for 422V+ fuel) was less than the limit of 2700 EF for this event. The zirconium-water reaction at the hot spot was 0.53 (422V+) and 0.67 (OFA) percent by weight, meeting the criterion of less than 16% zirconium-water reaction. Thus, the acceptance criteria was satisfied for this accident and the regulatory requirements continue to be met for the proposed EPU conditions.

Conclusion

The NRC staff reviewed the licensee's analyses of the sudden decrease in core coolant flow events and concluded the licensee's analyses adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concluded that the licensee demonstrated that the reactor protection and safety systems will continue to ensure that the ability to insert control rods is maintained, the RCPB pressure limits will not be exceeded, and adequate core cooling will be provided. Based on this, the NRC staff concluded that the plant will continue to meet the requirements of GDCs 27, and 28, following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the sudden decrease in core coolant flow events.

2.8.5.4 Reactivity and Power Distribution Anomalies

2.8.5.4.1 Uncontrolled Control Rod Assembly Withdrawal from a Subcritical or Low Power Startup Condition

Regulatory Evaluation

An uncontrolled control rod assembly withdrawal from subcritical or low power startup conditions may be caused by a malfunction of the reactor control or rod control systems. This withdrawal will uncontrollably add positive reactivity to the reactor core, resulting in a power excursion. The NRC staff's review covered (1) the description of the causes of the transient and the transient itself, (2) the initial conditions, (3) the values of reactor parameters used in the analysis, (4) the analytical methods and computer codes used, and (5) the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 20, insofar as it requires that the RPS be designed to initiate automatically the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded as a result of AOOs; and (3) GDC 25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems. Specific review criteria are contained in SRP Section 15.4.1 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The rod withdrawal from subcritical condition condensate and feedwater system (RWFSC) accident is defined as an uncontrolled addition of reactivity to the reactor core caused by withdrawal of rod control cluster assembly banks resulting in a power excursion.

By definition, this event occurs while the core is in a subcritical condition. Therefore, it is not expected that this event would be materially affected by an increase in rated power level. However, the licensee's request for an EPU includes a transition from the current fuel system, the Westinghouse OFA with ZIRLO™ cladding to the Westinghouse 422V+ fuel design. Therefore, the licensing report provides analyses in order to account for the change in fuel design that is associated with the proposed EPU.

The RWFSC event is classified as an ANS Condition II event (Reference 34). The analysis acceptance criteria require that DNBR remain above the SAL, that pressure in the RCS and MSS be limited to levels below 110% of their respective design pressures, and that the pressurizer does not become water-solid (to show that the event could not develop into a more serious event by sticking open a PORV that has relieved water).

In the analyses, reactor trip is assumed to occur when the low setting of the power range high neutron flux trip logic is reached. A 10% uncertainty in the power range flux trip setpoint is added, raising it from its nominal value of 25%, to 35%. No credit is taken for the source range or intermediate range neutron flux reactor trip signals.

The maximum positive reactivity insertion rate assumed (75 pcm/sec) is greater than that for the simultaneous withdrawal of the two sequential control banks having the greatest combined worth at the maximum rod withdrawal speed. The initial power level is assumed to be 10^{-9} (fraction of nominal power), which is below the power level that is expected for any shutdown condition. This combination of high reactivity insertion rate and low initial power level produces the highest peak heat flux.

Only one of the two RCPs is assumed to be operating. The reduced flow rate is conservative with respect to calculated DNBR. DNBR is calculated using the STDP methodology, that stipulates the assumption of TDF (for one RCP operating). The STDP methodology is applied because the conditions resulting from the transient are outside the range of applicability of the RTDP methodology (Reference 37).

The analysis is performed in three stages: first, an average core nuclear power transient calculation; second, an average core heat transfer calculation; third, a DNBR calculation. The TWINKLE code (Reference 63), a spatial neutron kinetics code, is used to determine the average power generation transient, including the various total core feedback effects (e.g., doppler and moderator reactivity. In the second stage, FACTRAN (Reference 64) is used to calculate the thermal heat flux transient based on the nuclear power transient calculated by TWINKLE. FACTRAN also calculates the fuel and clad temperatures. In the final stage, the average heat flux is used by VIPRE (Reference 35) to calculate the transient DNBR. These codes have been approved by the NRC.

The results of these analyses show that the DNBR remains above the SAL value. The peak fuel centerline temperatures (2108 EF for the 422V+ fuel and 2305 EF for the OFA fuel) are well below the minimum temperature where fuel melting would be expected (4800 EF). The minimum DNBR, below the first mixing vane grid (422V+ fuel), is 1.987 for a typical cell. This is well above the applicable DNBR SAL of 1.447. Above the mixing vane grid (422V+ fuel), the minimum DNBR is 1.951 for a thimble cell, also well above the applicable DNBR SAL (1.302).

Therefore, the RWFSC event analysis meets Condition II acceptance criteria, since the combination of thermal power and coolant temperature transients result in minimum DNBRs that are greater than their corresponding SAL values. The maximum fuel temperatures predicted to occur during this event are also less than those required for fuel melting to occur.

Based upon the input parameters, assumptions, and modeling techniques described in licensing report Section 2.8.5.4.1, the NRC staff finds the Ginna RWFSC analyses to be acceptable. The staff finds that the licensee has provided reasonable assurance that all of the acceptance criteria continue to be met at the proposed EPU conditions.

Conclusion

The NRC staff has reviewed the licensee's analyses of the uncontrolled control rod assembly withdrawal from a subcritical or low power startup condition and concludes that the licensee's analyses have adequately accounted for the changes in core design necessary for operation of the plant at the proposed power level. The NRC staff also concludes that the licensee's analyses were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure the SAFDLs are not exceeded. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 20, and 25 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the uncontrolled control rod assembly withdrawal from a subcritical or low power startup condition.

2.8.5.4.2 Uncontrolled Control Rod Assembly Withdrawal at Power

Regulatory Evaluation

An uncontrolled control rod assembly withdrawal at power (RWAP) may be caused by a malfunction of the reactor control or rod control systems. This withdrawal will uncontrollably add positive reactivity to the reactor core, resulting in a power excursion. The NRC staff's review covered (1) the description of the causes of the AOO and the description of the event itself, (2) the initial conditions, (3) the values of reactor parameters used in the analysis, (4) the analytical methods and computer codes used, and (5) the results of the associated analyses. The NRC's acceptance criteria are based on (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 20, insofar as it requires that the RPS be designed to initiate automatically the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded as a result of AOOs; and (3) GDC 25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems. Specific review criteria are contained in SRP Section 15.4.2 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

During a RWAP event, SG heat removal rate lags behind the core power generation rate until the SG pressure reaches the setpoint of the SG relief or safety valves. The difference between the heat removal and heat generation rates causes the reactor coolant temperature to rise until the reactor is tripped. Therefore, the RWAP could eventually result in a violation of the DNBR SAL.

The RWAP event is generally terminated by an automatic reactor trip from the power range high neutron flux trip signal, or the OTΔT trip signal. Reactor trip might also occur on high-pressurizer pressure or water level.

The RWAP is considered to be an ANS Condition II event (Reference 34). The principal analysis acceptance criteria for Condition II events require that the minimum DNBR remain above the DNBR SAL throughout the transient, and that pressure in the RCS and MSS be limited to levels less than 110% of their respective design pressures.

The licensee has analyzed RWAP cases for the event's potential effects upon thermal margin (i.e., low DNBR), and RCS pressure.

For the DNB cases, the analyses encompassed a range of reactivity insertion rates for both minimum and maximum reactivity feedback conditions at three power levels. Since the RWAP event was analyzed with the RTDP (Reference 37), initial reactor power, RCS pressure, and RCS temperature were assumed to be at their nominal values, and minimum measured RCP flow was assumed. Uncertainties in the initial conditions were included in the DNBR limit as described in the RTDP.

Minimum reactivity feedback conditions were modeled by using a moderator temperature coefficient (MTC) of +5 pcm/°F for power levels less than 70%, consistent with Ginna's TSs. For the full power cases, an MTC of 0 pcm/°F was assumed. Minimum reactivity feedback conditions were modeled by using a large, positive moderator density coefficient of 0.45 Δk/g/cc, which corresponds to a large negative MTC.

A range of reactivity insertion rates was examined. The maximum positive reactivity insertion rate was greater than that which would be obtained from the simultaneous withdrawal of the two control rod banks having the maximum combined worth at a conservative speed (48.125 inches/minute, which corresponds to 77 steps/minute).

Power levels of 10, 60, and 100% of the NSSS power (1817 MWt) were considered. For the Ginna RWAP analyses, credit for reactor tip was limited to signals from high neutron flux and the OTΔT reactor trip logic. The staff agrees with this assumption, since these two reactor trip signals are most directly related to thermal margin (i.e., decreasing DNBR).

The RWAP event was analyzed with RETRAN (Reference 32), and NRC-accepted computer code that simulates the core neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, SGs, and main steam safety valves (MSSVs). The program computes pertinent plant variables including temperatures, pressures, power level, and DNBR.

Results of the DNB cases are assembled from the set of transient analyses and presented as a map of resulting minimum DNBRs, plotted as a function of insertion rate and reactivity feedback conditions, for each initial power level analyzed. It is evident, from this map, that the range of RWAP DNBR cases was protected by the high neutron flux and OTΔT reactor trip functions. At the higher reactivity insertion rates, the first reactor trip signal generated is from high neutron flux. At the slower reactivity insertion rates, the first reactor trip signal generated is from OTΔT. The minimum DNBR, identified from all these cases (1.384), was greater than the DNBR SAL (1.38).

In addition to the DNB cases, the licensee considered two pressure cases, to show that the RCS and MSS peak pressures do not exceed 110% of their respective design pressures. The RWAP was assumed to occur at 10% power, less 2% uncertainty, at nominal RCS pressure. Pressure measurement uncertainty was added for one case and subtracted for another case. RTDP was not used, since this was not a DNB evaluation. Instead, the transient initial conditions included uncertainties and the assumed flow was at the TDF level. The minimum MTC consistent with the power level (+5 pcm/°F) was assumed.

The results of the RCS pressure cases indicate that the RCS and MSS peak pressures (2748.1 psia and 1207.7 psia) do not exceed 110% of their respective design pressures for reactivity insertion rates that are slower than or equal to 55 pcm/sec. This maximum reactivity insertion rate is a reload limit which is reconfirmed for each reload. For the RCS pressure cases, credit was taken for the reactor trip on high pressurizer pressure, which occurs shortly after the start of the accident. The NRC staff agrees with this approach, since the credited trip function is directly related to the parameter of interest (RCS pressure).

Based upon the input parameters, assumptions, and modeling techniques described in licensing report Section 2.8.5.4.2, the NRC staff finds the Ginna RWFSC analyses to be acceptable. The staff finds that the licensee has provided reasonable assurance that all of the acceptance criteria continue to be met at the proposed EPU conditions.

<u>Conclusion</u>

The NRC staff has reviewed the licensee's analyses of the uncontrolled control rod assembly withdrawal at power event and concludes that the licensee's analyses have adequately accounted for the changes in core design required for operation of the plant at the proposed power level. The NRC staff also concludes that the licensee's analyses were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure the SAFDLs are not exceeded. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 20, and 25 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the uncontrolled control rod assembly withdrawal at power.

2.8.5.4.3 Control Rod Misoperation

Regulatory Evaluation

The NRC staff's review covered the types of control rod misoperations that are assumed to occur, including those caused by a system malfunction or operator error. The review covered (1) descriptions of rod position, flux, pressure, and temperature indication systems, and those actions initiated by these systems (e.g., turbine runback, rod withdrawal prohibit, rod block) that can mitigate the effects or prevent the occurrence of various misoperations; (2) the sequence of events; (3) the analytical model used for analyses; (4) important inputs to the calculations; and (5) the results of the analyses. The NRC's acceptance criteria are based on (1) GDC 10, insofar as it requires that the reactor core be designed with appropriate margin to assure that SAFDLs (SAFDLs) are not exceeded during any condition of normal operation, including the effects of AOOs; (2) GDC 20, insofar as it requires that the protection system be designed to initiate the reactivity control systems automatically to assure that acceptable fuel design limits are not exceeded as a result of AOOs and to initiate automatically operation of systems and components important to safety under accident conditions; and (3) GDC 25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems. Specific review criteria are contained in SRP Section 15.4.3 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The RCCA misalignment events include the dropping of one or more RCCAs within the same group, and the dropping of an RCCA bank, and statically misaligning an RCCA.

A dropped RCCA or RCCA bank is detected by a sudden drop in the core power level, an asymmetric power distribution, a rod at bottom signal, a rod deviation alarm, or the rod position indication. Misaligned RCCAs are detected by an asymmetric power distribution, a rod deviation alarm, or the rod position indicators.

The control rod misoperation events are considered to be ANS Condition II events (Reference 34). The principal analysis acceptance criteria for Condition II events require that the minimum DNBR remain above the DNBR SAL throughout the transient, and that pressure in the RCS and MSS be limited to levels less than 110% of their respective design pressures.

For Westinghouse plants, the RCCA misalignment events were analyzed generically. Statepoints from the generic analyses were evaluated using the VIPRE (Reference 35) computer code, and the Westinghouse Dropped Rod Methodology (Reference 56), to verify that the minimum DNBR, under EPU conditions, would continue to remain above the DNBR SAL. The VIPRE computer code and the Westinghouse Dropped Rod Methodology have been previously reviewed and accepted by the staff. The Westinghouse Dropped Rod Methodology constructs dropped rod limit lines that permit the determination of the power level, given temperature and pressure, that is commensurate with the DNBR SAL.

The Westinghouse Dropped Rod Methodology is used to evaluate transient statepoints, from the generic analyses, for Ginna on a cycle-specific basis during the reload process. Assuming the high end of the T_{avg} range (576 EF), the limiting EPU margin is 0.06% for the 422V+ fuel, and 1.62% for the OFA fuel. Currently, the dropped rod limit margin is about 1.8%. Therefore, a dropped RCCA or RCCA bank in the Ginna core would not lead to DNB.

RCCA misalignment events, if they require protective action, generate the reactor trip signal through the OTΔT protection logic. The results of Ginna's evaluation, for the RCCA misalignment events, indicate that the DNBR remains above the DNBR SAL (1.38), and that the peak linear heat generation rate remains below the value which would result in fuel centerline melt (22.7 kW/ft).

The licensee states that the results and conclusions of this analysis will be confirmed on a cycle-specific basis as part of the Ginna reload process.

<u>Conclusion</u>

The NRC staff has reviewed the licensee's analyses of control rod misoperation events and concludes that the licensee's analyses have adequately accounted for the changes in core design required for operation of the plant at the proposed power level. The NRC staff also concludes that the licensee's analyses were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure the SAFDLs will not be exceeded during normal or anticipate operational transients. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 20, and 25 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to control rod misoperation events.

2.8.5.4.4 Startup of an Inactive Loop at an Incorrect Temperature

Regulatory Evaluation

A startup of an inactive loop transient may result in either an increased core flow or the introduction of cooler or deborated water into the core. This event causes an increase in core reactivity due to decreased moderator temperature or moderator boron concentration. The NRC staff's review covered (1) the sequence of events, (2) the analytical model, (3) the values of parameters used in the analytical model, and (4) the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs; (2) GDC 20, insofar as it requires that the protection system be designed to automatically initiate the operation of appropriate systems to ensure that SAFDLs are not exceeded as a result of operational occurrences; (3) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design condition of the RCPB are not exceeded during AOOs; (4) GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other RV internals so as to significantly impair the capability to cool the core; and (5) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.4.4-5 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

A startup of an inactive loop transient can cause an increase in core reactivity due to a cooldown in the core or a reduction in core boron concentration. Since Ginna does not have loop isolation valves, there will always be some flow in both loops, even if one RCP is idle, and boron concentration will be the same, everywhere in the RCS. Therefore, the core is not susceptible to the introduction of water of a lower boron concentration simply by starting an RCP or opening a loop isolation valve.

The startup of an inactive loop event is considered to be an ANS Condition II event (Reference 34). The principal analysis acceptance criteria for Condition II events require that the minimum DNBR remain above the DNBR SAL throughout the transient, and that pressure in the RCS and MSS be limited to levels less than 110% of their respective design pressures.

The plant is assumed to be initially at steady state, at a low power level, with one RCP in operation. Then the second RCP is started, increases core flow to the nominal full flow condition.

Since the Ginna TSs preclude operation with an RCS loop out of service above 8.5% power, this event is considered only at power levels of 8.5% RTP and below. The Ginna UFSAR analysis was performed at 8.5% power and assumed a conservatively high temperature difference between the active loop cold leg and the inactive loop hot leg (20 EF).

Under the proposed EPU conditions, the temperature difference between the operating and idle loops is not much different than the current temperature difference. Similarly, the moderator density coefficient limits are essentially unchanged. The high temperature difference between the active loop cold leg and the inactive loop hot leg that was assumed for the Ginna UFSAR analysis remains conservative for the proposed EPU conditions. Therefore, the NRC staff agrees that a new analysis is not necessary for this event. The staff also agrees with the licensee's conclusion, i.e., the conclusions presented in UFSAR Chapter 15.4.3, "Startup of an Inactive Reactor Coolant Loop," will remain valid under the proposed EPU conditions.

Conclusion

The NRC staff has reviewed the licensee's analyses of the inactive loop startup event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, 20, 26, and 28 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the increase in core flow event.

2.8.5.4.5 Chemical and Volume Control System Malfunction that Results in a Decrease in Boron Concentration in the Reactor Coolant

Regulatory Evaluation

The CVCS malfunction that results in a decrease in boron concentration in the reactor coolant is commonly referred to as the boron dilution event. Unborated water can be added to the RCS, via the CVCS. This may happen inadvertently because of operator error or CVCS malfunction, and cause an unwanted increase in reactivity and a decrease in shutdown margin. The operator should stop this unplanned dilution before the shutdown margin is eliminated. The NRC staff's review covered (1) conditions at the time of the unplanned dilution, (2) potential causes of dilution events, (3) initiating events, (4) the sequence of events, (5) the analytical model used for analyses, (6) the values of parameters used in the analytical model, and (7) results of the analyses. The NRC's acceptance criteria are based on (1) GDC 10, insofar as it requires that the reactor core and associated coolant, control, and protection systems be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including AOOs; (2) GDC 15, insofar as it requires that the RCS and associated auxiliary, control, and protection systems be designed with sufficient margin to assure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including AOOs; and (3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.4.6 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

SRP Section 15.4.6 stipulates that boron dilution events be considered for all modes of operation. Typically the way licensees show acceptable results for boron dilution events is to demonstrate the operators have sufficient time to terminate the boron dilution before there is a complete loss of shutdown margin (SDM). If SDM is not lost, then the reactor does not return to criticality and boron dilution is bounded by other analyses. This is the means that Ginna has chosen to show acceptable results. The SRP acceptance criteria specify that the operator must have at least 15 minutes from notification of the onset of a boron dilution event until SDM is lost, when in Modes 1, 2, 3, 4, and 5, and at least 30 minutes when in Mode 6. The licensee's UFSAR and licensing report indicate that these SRP acceptance criteria would apply to Ginna. However, the UFSAR and licensing report do not contain analyses to address these acceptance criteria. Specifically, there are no analyses for Modes 3 and 4. When asked to identify Ginna's licensing basis, the licensee stated (Reference 26) that its licensing basis pre-dates RG 1.70, Revision 2, and that the boron dilution event, in Modes 3 and 4, is not part of the Ginna licensing basis. Typically, the boron dilution acceptance criteria for commercial reactors licensed before RG 1.70 Revision 2, specifies that the operator have at least 15 minutes from onset of a boron dilution event until SDM is lost, when in Modes 1 and 2, and at least 30 minutes when in Mode 6. In addition to those requirements, Ginna has subsumed a requirement to include a boron dilution analysis for Mode 5. Therefore, the staff reviewed the EPU analyses according to the current Ginna licensing basis, not the SRP guidance.

The boron dilution event is affected by the EPU, since the analysis is dependent on the initial boron concentration, critical boron concentration, system volume, and required SDM. The boron dilution analysis is also dependent on various flow rates that may or may not be changed due to other requirements associated with the EPU. The following table shows how the EPU affects these parameters.

Boron Dilution Parameters

	Initial Boron Concentration (ppm)	Critical Boron Concentration (ppm)	Dilution Flow (gpm)	Dilution Volume (ft^3)
Mode 1				
Pre-EPU	1650	1300	127	4696.9
Post-EPU	2100	1800	127	5123.0
Mode 2				
Pre-EPU	1750	1500	120	4696.9
Post-EPU	2000	1800	120	5123.0
Mode 6				
Pre-EPU	1700	1330	120	2000.0
Post-EPU	initial/critical ratio of 1.2914		120	2042.0

The table indicates that the boron dilution analysis, performed for the EPU, is based upon different initial and final boron concentrations, and system volumes.

Since the EPU would require more fuel to be loaded into the core, in order to achieve the higher power level for the entire cycle, it would be necessary to increase the amount of boron addition to offset the additional positive reactivity. The table, therefore, lists higher initial and final boron concentrations.

The difference between the initial and final boron concentrations is smaller for the EPU analyses, compared to the current (pre-EPU) analyses. This is indicative of a decrease in the SDM available, as shown in licensing report Table 2.8.2-1, “Range of Key Safety Parameters.” The amount of time it takes to dilute is directly proportional to the natural log of the ratio of initial to final boron concentrations.

In order to compensate for the decrease in available SDM, the licensee has increased the effective RCS volume. The amount of time it takes to dilute away the SDM is directly proportional to the system volume. For Modes 1 and 2 the increase in volume is attributable to the assumption that fewer SG tubes will be plugged (10% vs the 15% SGTP level that is assumed in the current analysis). The 10% SGTP assumed in the EPU analysis is consistent with licensing report Section 1.1, “Nuclear Steam Supply System Parameters.” In calculating the volume for Modes 1 and 2, the licensee did not include the effect of thermal expansion of the steel piping and components, or the volumes of the pressurizer and pressurizer surge line, that are not in the active flow region. Incorporating these factors into the calculation would increase the effective RCS volume. Therefore, the staff agrees that excluding these factors results in an effective RCS volume that is conservative for the boron dilution analysis.

The increase in volume for Mode 6 is attributable to a change in analysis assumptions. The licensee’s current assumption is that the RV is filled only to the mid-plane of the hot leg and that the volume of water in the RHRS is not included. The EPU analysis is based upon the assumptions that the RV is full, except for the upper head, and that water in the RHR system is included. Assuming the RV is only filled to the mid-plane of the hot leg would be conservative, since this would account for occasions when the RCS is drained for work on the SGs, and it would reduce the time needed for dilution. The two volume assumptions translate to a difference of only 30 seconds in the time available to the operator. Since the licensee has determined that there are 32 minutes available for operator action, the 30 second difference does not change the analysis conclusion that the acceptance criteria continue to be met. As such, the NRC staff concludes that the existing boron dilution event analysis for Mode 6 is acceptable for the proposed EPU conditions.

For Mode 5, the licensee proposes to use administrative controls to preclude a boron dilution event, in a reduced inventory situation, and to otherwise assure that at least 15 minutes will be available for operator action to terminate a boron dilution event. Since the NRC has previously accepted administrative controls to preclude boron dilution events in the lower modes, it is reasonable to accept administrative controls in this instance. Absent the reduced inventory condition, which would significantly reduce the volume, the Mode 5 analysis would be similar to the analysis for Modes 1 and 2, and would yield similar results.

The following table shows the pre-EPU and post-EPU results for the boron dilution event.

Condition	Post-EPU	Pre-EPU	Limit
Mode 1 Manual Rod Control	47.2 Minutes	30.3 Minutes	15 Minutes
Mode 1 Auto Rod Control	37.7 Minutes	33.3 Minutes	15 Minutes
Mode 2	33.9 Minutes	25.1 Minutes	15 Minutes
Mode 5	>15 Minutes	>15 Minutes	15 Minutes
Mode 6	32.0 Minutes	30.08 Minutes	30 Minutes

Based upon the input parameters, assumptions, and modeling techniques described in licensing report Section 2.8.5.5.5, the NRC staff finds the Ginna boron dilution calculations to be acceptable. The licensee provided reasonable assurance that all of the acceptance criteria continue to be met at the proposed EPU conditions.

Conclusion

The NRC staff has reviewed the licensee's analyses of the decrease in boron concentration in the reactor coolant due to a CVCS malfunction and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the decrease in boron concentration in the reactor coolant due to a CVCS malfunction.

2.8.5.4.6 Spectrum of Rod Ejection Accidents

Regulatory Evaluation

Control rod ejection accidents cause a rapid positive reactivity insertion together with an adverse core power distribution, which could lead to localized fuel rod damage. The NRC staff evaluates the consequences of a control rod ejection accident to determine the potential damage caused to the RCPB and to determine whether the fuel damage resulting from such an accident could impair cooling water flow. The NRC staff's review covered initial conditions, rod patterns and worths, scram worth as a function of time, reactivity coefficients, the analytical model used for analyses, core parameters which affect the peak reactor pressure or the probability of fuel rod failure, and the results of the transient analyses. The NRC's acceptance criteria are based on GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other RV internals so as to impair significantly the capability to cool the core. Specific review criteria are contained in SRP Section 15.4.8 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The rod ejection accident is defined as a mechanical failure of a control rod drive mechanism pressure housing resulting in the ejection of the RCCA and drive shaft. The consequence of this mechanical failure is a rapid positive reactivity insertion together with an adverse core power distribution, possibly leading to localized fuel rod damage. The resultant core thermal power excursion is limited by the Doppler reactivity effect of the increased fuel temperature and terminated by a reactor trip actuated by high nuclear power signals.

The RCCA ejection accident, is classified as an ANS Condition IV event (Reference 34). As such, some fuel damage is considered to be an acceptable consequence. The acceptance criteria for this event are based upon long-term core cooling, and offsite dose consequences that remain within the guidelines of 10 CFR 50.67. The criterion applied by Ginna to ensure the core remains in a coolable geometry following a rod ejection incident is that the average fuel pellet enthalpy at the hot spot must remain less than 200 cal/g (360 Btu/lbm). Peak reactor coolant pressure is required to be less than that which could cause RCS stresses to exceed the faulted-condition stress limits. Fuel melting must be limited to less than 10% of the pellet volume at the hot spot even if the average fuel pellet enthalpy is below the 360 Btu/lbm fuel enthalpy limit.

Overpressurization of the RCS during a rod ejection event was addressed generically (Reference 65) by Westinghouse, and was determined to be adequate for the Ginna EPU. The RCS pressure limit is 3200 psig.

As a result of a fuel failure during a test at the CABRI reactor in France in 1993, and one in 1994 at the NSRR test reactor in Japan, the NRC recognized that high burnup fuel cladding might fail during a reactivity insertion accident (RIA), such as a rod ejection event, at lower enthalpies than the limits currently specified in RG 1.77, "Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors." However, generic analyses performed by all of the reactor vendors have indicated that the fuel enthalpy during RIAs will be much lower than the RG 1.77 limits, based on their 3D neutronics calculations. For high burnup fuel that has been burned so long that it no longer contains significant reactivity, the fuel enthalpies calculated using the 3D models are expected to be much lower than 100 cal/g.

The NRC staff has concluded that although the RG 1.77 limits may not be conservative for cladding failure, the analyses performed by the vendors, which have been confirmed by NRC-sponsored calculations, provide reasonable assurance that the effects of postulated RIAs in operating plants with fuel burnups up to 60 gigawatt days per metric ton uranium, will neither: (1) result in damage to RCPB, nor (2) sufficiently disturb the core, its support structures, or other RV internals to impair significantly the capability to cool the core as specified in current regulatory requirements.

Conclusion

The NRC staff has reviewed the licensee’s analyses of the rod ejection accident and concludes that the licensee’s analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that appropriate reactor protection and safety systems will prevent postulated reactivity accidents that could (1) result in damage to the RCPB greater than limited local yielding, or (2) cause sufficient damage that would significantly impair the capability to cool the core. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDC 28 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the rod ejection accident.

2.8.5.5 Inadvertent Operation of ECCS and Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory

Regulatory Evaluation

Equipment malfunctions, operator errors, and abnormal occurrences could cause unplanned increases in reactor coolant inventory. Depending on the boron concentration and temperature of the injected water and the response of the automatic control systems, a power level increase may result and, without adequate controls, could lead to fuel damage or overpressurization of the RCS. Alternatively, a power level decrease and depressurization may result. Reactor protection and safety systems are actuated to mitigate these events. The NRC staff's review covered (1) the sequence of events, (2) the analytical model used for analyses, (3) the values of parameters used in the analytical model, and (4) the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design conditions of the RCPB are not exceeded during AOOs; and (3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.5.1-2 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The licensing report does not contain a section to address the class of accidents that result in an increase in reactor coolant inventory. This evaluation is based upon information that was obtained from Ginna's UFSAR, and from the licensee, by means of the RAI process.

a. Inadvertent Operation of ECCS

An inadvertent actuation of the ECCS at power event, an ANS Condition II event (Reference 34), could be caused by operator error or a false electrical actuating signal. Actuation of the ECCS trips the reactor, and starts the safety injection pumps, which pump borated water from the refueling water storage tank into the cold leg of each RCS loop; but only when the RCS pressure is below the shutoff head of the safety injections pumps (about 1500 psia). Although the safety injection pumps would be started, they could not deliver any flow to the RCS at nominal operating pressure. Therefore, the inadvertent ECCS actuation at-power event, in the Ginna plant, would amount to little more than a spurious reactor trip.

b. Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory

The chemical and volume control system (CVCS) provides the means for (a) maintaining water inventory and quality in the RCS, (b) supplying seal-water flow to the RCPs and pressurizer auxiliary spray, (c) controlling the boron neutron absorber concentration in the reactor coolant, and (d) controlling the primary water chemistry and reducing coolant radioactivity level, and (e) supplying recycled coolant for demineralized water makeup for normal operation.

The CVCS malfunction, an ANS Condition II event (Reference 34), might be caused by an operator error or an electrical fault (e.g., the pressurizer level channel that controls the charging flow fails “low,” causing the charging system flow to increase to make up for the perceived lack of inventory). Pressurizer level would rise, and the reactor would trip on high pressurizer level; but the charging flow would continue, unabated, until it is terminated by the operator. If the pressurizer fills and causes water to be relieved through the PORVs or safety valves, then these valves could stick open and create an SBLOCA, an ANS Condition III event. This would violate the ANS Condition II acceptance criterion that prohibits the escalation of a Condition II event into a more serious event. Satisfaction of this acceptance criterion is often demonstrated by showing that sufficient time exists for the operator to recognize the situation and end the charging flow before the pressurizer can fill.

Ginna is equipped with three positive displacement charging pumps that can deliver a maximum of 180 gpm (charging flow is normally maintained at 46 gpm). Under the proposed EPU conditions, the nominal steam volume in the pressurizer would be 333 cu. ft. This is less than the current 397 cu. ft. nominal steam volume. The staff calculated that it would take almost 14 minutes to displace 333 cu. ft. at the maximum charging flow rate. This question was discussed during the Ginna audit (Reference 24) and raised again in an RAI. In response (Reference 26), the licensee refined the staff’s estimate by taking into account the charging line pressure drop and operation of the associated relief valves. If all three charging pumps were running at maximum speed with the RCS at normal pressure, the charging pump discharge pressure required to force 180 gpm into the RCS would lift the charging pump relief valves and divert a portion of the charging flow back to the volume control tank. Prior to reactor trip, the licensee estimates that the maximum deliverable flow to the RCS would be less than 150 gpm. At this rate it would take approximately 6 minutes to fill the pressurizer to the high level reactor trip setpoint. Following the reactor trip, the RCS cools down and depressurizes slightly, causing an expansion of the pressurizer steam volume. The small depressurization, after the reactor trip does not present a DNB concern; but it can lead to an increase in charging flow, which is conservatively assumed to reach 180 gpm. At this rate, it would take an additional 12 minutes to fill the pressurizer, after the reactor trip. Therefore, the total time to fill the pressurizer is estimated to be about 18 minutes.

The licensee also stated that the plant is normally run with only two charging pumps in operation. The example of starting all charging pumps due to the failure of the controlling pressurizer level channel does not apply to Ginna, since the Ginna charging pumps must be started manually (no auto start feature). There are alarms to alert the operator for high pressurizer level, high pressurizer pressure, and low volume control tank level. These alarms and design features provide added assurance that 18 minutes would be considered a sufficient period in which the operator can recognize and terminate the event.

The NRC staff finds that the inadvertent ECCS actuation at-power event, in the Ginna plant, would amount to little more than a spurious reactor trip. The staff also finds that a CVCS malfunction would be terminated by the operator before the pressurizer would fill.

Conclusion

The NRC staff reviewed the licensee's analyses of the inadvertent ECCS actuation at-power event and concluded that the licensee's evaluations were performed using acceptable methods and assumptions. The NRC staff also concluded that the plant will continue to meet the regulatory requirements following implementation of the proposed EPU program. Therefore, the NRC staff finds the proposed EPU program acceptable with respect to the inadvertent ECCS actuation at-power and the CVCS malfunction events.

2.8.5.6 Decrease in Reactor Coolant Inventory

2.8.5.6.1 Inadvertent Opening of Pressurizer Pressure Relief Valve

Regulatory Evaluation

The inadvertent opening of a pressure relief valve results in a reactor coolant inventory decrease and a decrease in RCS pressure. Prior to a reactor trip, the decrease in RCS pressure can cause a reduction in thermal margin. A reactor trip normally occurs due to OTΔT or low RCS pressure. The NRC staff's review covered (1) the sequence of events, (2) the analytical model used for analyses, (3) the values of parameters used in the analytical model, and (4) the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including AOOs; and (3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.6.1 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The inadvertent opening of a pressurizer relief valve is conservatively modeled by assuming the opening of a pressurizer safety valve, since a safety valve is sized to relieve approximately 40% more steam flow than a relief valve. The event results in a rapidly decreasing RCS pressure, that could lead to a reactor trip on low pressurizer pressure or OTΔT.

The inadvertent opening of a pressurizer relief valve is considered to be an ANS Condition II event (Reference 34). The principal analysis acceptance criterion for this Condition II event requires that the minimum DNBR remain above the DNBR SAL throughout the transient.

The DNBR transient is calculated using the RTDP (Reference 37). Accordingly, initial core power, RCS pressure, and RCS temperature were assumed to be at their nominal values, consistent with steady-state full-power operation. Minimum measured flow was modeled. The initial core power level assumed is 1811 MWt. The moderator temperature coefficient of reactivity was assumed to be zero, in order to minimize the amount of negative reactivity feedback due to changes in moderator temperature. Similarly, a low value for the Doppler coefficient of reactivity was assumed. Voiding, due to local or subcooled boiling, was also assumed to have no effect upon core reactivity feedback or core power shape.

The event was analyzed with the RETRAN (Reference 32) code. RETRAN is an NRC-accepted code that simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, SG, and SG safety valves, and calculates values for key plant parameters, such as temperatures, pressures, and power level.

The licensing report analysis results indicate that the reactor trip occurs on OTΔT, and the minimum DNBR is reached shortly after the rods begin to drop. The DNBR remains above the limit value of 1.38 throughout the transient.

The licensing report analysis results show that the reactor trip, from the OTΔT signal, provides adequate protection against the inadvertent opening of a pressurizer relief valve event, since the minimum DNBR remains above the SAL throughout the transient. Therefore, no cladding damage or release of fission products to the RCS is predicted for this event.

In Ginna's current licensing basis, this event was only assessed as a small break in the pressurizer vapor space using a generic evaluation (Reference 57) of the inadvertent opening of a pressurizer relief valve. Thus, the evaluation was only concerned with the possibility of uncovering the core. In that regard, protection for the small break in the pressurizer vapor space is provided by the ECCS. During its evaluation for the EPU, the licensee determined that this event should also be considered as a Condition II event (i.e., no DNB allowed), which is protected by the OTΔT RPS function.

Based on the staff's review, the analysis was done with methods that are acceptable to the NRC. The results demonstrated that the DNBR SAL acceptance criterion for this ANS Condition II event was met. Therefore, the staff agrees that the licensee has adequately addressed the inadvertent opening of a pressurizer relief valve under the proposed EPU conditions.

Conclusion

The NRC staff has reviewed the licensee's analyses of the inadvertent opening of a pressurizer pressure relief valve event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the inadvertent opening of a pressurizer pressure relief valve event.

2.8.5.6.2 Steam Generator Tube Rupture

Regulatory Evaluation

A SG tube rupture (SGTR) event causes a direct release of radioactive material contained in the primary coolant to the environment through the ruptured SG tube and main steam safety or atmospheric relief valves. Reactor protection and emergency safeguards functions are actuated to mitigate the accident and restrict the offsite dose to within the guidelines of 10 CFR 50.67. The NRC staff's review covered (1) postulated initial core and plant conditions, (2) method of thermal and hydraulic analysis, (3) the sequence of events (assuming offsite power either available or unavailable), (4) assumed reactions of reactor system components, (5) functional and operational characteristics of the RPS, (6) operator actions consistent with the plant's EOPs, and (7) the results of the accident analysis. A single failure of a mitigating system was assumed for this event. The NRC staff's review of the SGTR is focused on the thermal and hydraulic analysis for the SGTR in order to confirm that the faulted SG does not experience an overfill. Preventing SG overfill is necessary in order to prevent the failure of main steam lines. Specific review criteria are contained in SRP Section 15.6.3 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

In 1996, both SGs were replaced at Ginna with B&WC SGs that are oversized for the licensed thermal power of 1520 MWt.

The complete severance of a SG tube is classified as an ANS Condition IV (Reference 34) limiting fault, since it can result in the loss of the reactor coolant system boundary or the release of significant amounts of radioactive material to the environment. Ginna's licensing basis includes the use of the alternate source term dose calculation methodology, and the dose criteria of 10 CFR 50.67. The staff's review of the SGTR with respect to 10 CFR 50.67 and the radiological consequences of an SGTR is described in Section 2.9.6 of this SE.

The SGTR event is addressed in licensing report Section 2.8.5.6.2 and UFSAR Chapter 15.6.3. The SGTR accident analyses includes analyses performed to demonstrate margin to overfill is within the allowable guidelines. Preventing SG overfill is necessary to prevent the release of water to the environment through the MSSVs or ARVs and to preclude the possibility of failure of main steam lines. The accident modeled is a double-ended break of one SG tube located at the top of the tube sheet on the outlet-cold-leg-side of the SG. The location of the break on the cold side of the SG results in higher primary-to-secondary leakage than a break on the hot side of the SG. The licensee analyzed this event with a LOOP. The licensee used the RETRAN (Reference 32) computer code to analyze the SGTR, in lieu of the current, licensing basis LOFTTR2 (Reference 69) methodology. RETRAN has been approved for use in SGTR analyses. The licensee considered SGTR cases at both ends of the nominal T_{avg} range, with and without 10% tube plugging.

The staff finds that the input parameters and assumptions are conservative, and consistent with the AOR. The results of the analysis indicate that there are at least 220 ft^3 of margin to overfill, based upon the total SG volume of 4512.7 ft^3. Therefore, the staff agrees that overfill of the ruptured SG would not occur for a design basis SGTR event at Ginna, under the proposed EPU conditions.

Conclusion

The NRC staff reviewed the licensee's analysis of the SGTR accident and concludes that the licensee's analysis has adequately accounted for operation of the plant at the proposed EPU level and was performed using acceptable analytical methods and approved computer codes. The NRC staff further concludes that the assumptions used in this analysis are conservative and that the event does not result in an overfill of the faulted SG. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the SGTR event.

2.8.5.6.3 Emergency Core Cooling System and Loss-of-Coolant Accidents

Regulatory Evaluation

LOCAs are postulated accidents that would result in the loss of reactor coolant from piping breaks in the RCPB at a rate in excess of the capability of the normal reactor coolant makeup system to replenish it. Loss of significant quantities of reactor coolant would prevent heat removal from the reactor core, unless the water is replenished. The reactor protection and ECCS systems are provided to mitigate these accidents. The NRC staff's review covered (1) the licensee's determination of break locations and break sizes; (2) postulated initial conditions; (3) the sequence of events; (4) the analytical model used for analyses, and calculations of the reactor power, pressure, flow, and temperature transients; (5) calculations of peak cladding temperature, total oxidation of the cladding, total hydrogen generation, changes in core geometry, and long-term cooling; (6) functional and operational characteristics of the reactor protection and ECCS systems; and (7) operator actions. The NRC's acceptance criteria are based on (1) 10 CFR 50.46, insofar as it establishes standards for the calculation of ECCS performance and acceptance criteria for that calculated performance; (2) 10 CFR Part 50, Appendix K, insofar as it establishes required and acceptable features of evaluation models for heat removal by the ECCS after the blowdown phase of a LOCA; (3) GDC 4, insofar as it requires that SSCs important to safety be protected against dynamic effects associated with flow instabilities and loads such as those resulting from water hammer; (4) GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; and (5) GDC 35, insofar as it requires that a system to provide abundant emergency core cooling be provided to transfer heat from the reactor core following any LOCA at a rate so that fuel clad damage that could interfere with continued effective core cooling will be prevented. Specific review criteria are contained in SRP Sections 6.3 and 15.6.5 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The ECCS consists of RHR system flow, upper plenum injection (UPI) flow, high-head safety injection (HHSI) flow delivered to the cold legs, and two accumulators with a cover gas pressure of 714.7 psia, also injecting into the cold legs. The shutoff head of the RHR low pressure injection pumps is 140 psia. The Ginna ECCS system is further described in the UFSAR Section 6.3 (Reference 20).

The proposed EPU represents a core power increase of about 16.8% above the current core power of 1520 MWt to 1811 MWt, which includes a 2% power uncertainty. The addition of 6 MWt for the two RCPs brings the NSSS power level to 1817 MWt. The LOCA and post-LOCA long-term cooling analyses conducted by the licensee and the NRC staff were performed at an NSSS power level of 1817 MWt.

a. LBLOCA

In an application dated April 29, 2005 (Reference 19), the licensee sought approval to implement Westinghouse's best-estimate large-break LOCA (BE LBLOCA) methodology (Reference 73) to its Ginna Nuclear Power Plant. This is NRC-approved methodology that uses the Automated Statistical Treatment of Uncertainty Method (ASTRUM). The licensee supplemented its application (Reference 19) with additional information (see References 18 and 29) that did not change the scope of the application.

In its April 29, 2005, application (Reference 19), the licensee stated, "Both Ginna LLC and its analysis vendor (Westinghouse) have ongoing processes which ensure that the values and ranges of the Best Estimate Large Break LOCA analysis inputs for peak cladding temperature and oxidation-sensitive parameters bound the ranges and values of the as-operated plant parameters."

The BE LBLOCA analyses were performed to demonstrate that the system design would provide sufficient ECCS flow to transfer the heat that is present in the reactor core following a LBLOCA at a rate such that (1) fuel and clad damage that could interfere with continued effective core cooling would be prevented, and (2) the clad metal-water reaction would be limited to less than that which would compromise cladding ductility and result in excessive hydrogen generation.

The NRC staff reviewed the licensee's evaluation of the ECCS performance analyses for Ginna, which were done in accordance with Westinghouse's BE LBLOCA methodology (Reference 73), at the proposed EPU conditions. These analyses were conducted for a mixed core consisting of Westinghouse OFA and 422V+ fuel assemblies. The NRC staff reviewed the analyses to assure that they met the acceptance criteria for ECCS performance, as specified in 10 CFR 50.46, and that Ginna's implementation was within the limitations and conditions stated in the staff's acceptance of the Westinghouse methodology (Reference 73).

The licensee's results for the calculated peak cladding temperatures (PCTs), the maximum cladding oxidation (local), and the maximum core-wide cladding oxidation are provided in the following table, along with the acceptance criteria of 10 CFR 50.46(b).

Parameter	422V+	OFA	10 CFR 50.46 Limits
Limiting Break Size/Location	DEG/PD*	DEG/PD*	N/A
Cladding Material	ZIRLO™	ZIRLO™	(Cylindrical) Zircaloy or ZIRLO™
Peak Clad Temperature	1870 EF	1814 EF	2200 EF (10 CFR 50.46(b)(1))
Maximum Local Oxidation	3.4 %	2.5 %	17.0% (10 CFR 50.46(b)(2))
Maximum Total Core-Wide Oxidation (All Fuel)	0.30 %	0.30 %	1.0% (10 CFR 50.46(b)(3))

* DEG/PD is a double ended guillotine break at the pump discharge.

In its supplemental information, the licensee indicated that zircaloy clad fuel would have pre-LOCA and as well as post-LOCA oxidation (i.e., pre-existing oxidation in addition to oxidation resulting from the LOCA) on the inside and outside cladding surfaces. The licensee also noted that the fuel with the highest post-LOCA oxidation would not be likely to be the same fuel that has the highest pre-LOCA oxidation. When the calculated pre-LOCA oxidation was factored into the BE LBLOCA analyses for the zircaloy clad fuel, consistent with the Westinghouse ASTRUM methodology, the sum of the calculated pre-LOCA and post-LOCA oxidation levels was small enough to limit the total local oxidation to less than the 17% acceptance criterion of 10 CFR 50.46(b)(2), even during a fuel pin's final cycle in the core. The NRC staff finds that this appropriately addressed the issue with pre-LOCA oxidation.

Core-wide oxidation relates to the amount of hydrogen generated during a LOCA. Since hydrogen that may have been generated during normal operation (i.e., pre-LOCA) will be removed from the reactor coolant system throughout the operating cycle, the NRC staff noted that pre-existing oxidation does not contribute to post-LOCA hydrogen generation, and therefore, it does not need to be addressed when determining whether the calculated total core-wide oxidation meets the 1.0% criterion of 10 CFR 50.46(b)(3).

The NRC staff concludes that the results of the licensee's BE LBLOCA analyses demonstrate compliance with 10 CFR 50.46(b)(1) through (b)(3) for the proposed EPU conditions, and that the Ginna core will continue to be amenable to cooling as required by 10 CFR 50.46(b)(4).

The NRC staff's review of the acceptability of the Westinghouse BE LBLOCA methodology (Reference 73) for Ginna focused on assuring that the Ginna-specific input parameters or bounding values and ranges (where appropriate) were used to conduct the analyses, that the analyses were conducted within the conditions and limitations of the NRC-approved Westinghouse BE LBLOCA methodology, and that the results satisfied the requirements of 10 CFR 50.46(b) at the proposed EPU power level. Based on its review, the NRC staff also concludes that the Westinghouse BE LBLOCA methodology (Reference 73) is applicable to the Ginna plant, operating under the proposed EPU conditions.

b. Downcomer Boiling

Downcomer boiling can be a concern during recovery of the core after a LBLOCA because the still-hot RV can heat the water in the downcomer to the point that the head of water in the downcomer would not be capable of maintaining a reflood rate sufficient to replenish the water boiled off the top of the core. This would cause fuel temperature to increase. It is possible that even after the hottest spot in the core is quenched, another spot in the core could reheat to a temperature that exceeds the original hot spot temperature.

The licensee provided the results of analyses (Reference 29) to address the issue of downcomer boiling. These results show the effects of downcomer boiling, and indicate that, in spite of downcomer boiling, Ginna would achieve a stable and sustained core quench. The analyses and results can be characterized by the following:

- The NRC-accepted WCOBRA-TRAC LOCA analysis computer code, which is part of the ASTRUM methodology (Reference 73), and based upon the COBRA/TRAC code (Reference 45), was employed by Ginna to perform the Ginna LBLOCA calculations. This is the same code that was used to originally identify the downcomer boiling issue. This code is known to properly model the downcomer boiling phenomenon.

- The Ginna ECCS and design features, both cold leg (accumulator) and upper plenum low pressure (pumped) injection, more effectively address the LBLOCA phenomena of concern than the more conventional cold leg or downcomer low pressure injection of other PWR ECCS designs.

- WCOBRA-TRAC best estimate analyses ordinarily predict downcomer boiling at a time that is less detrimental to the predicted consequences of the LOCA than do the 10 CFR Part 50, Appendix K models.

Therefore, the NRC staff concluded that the licensee has demonstrated that Ginna can achieve a stable and sustained quench after the most severe LOCA within its design basis. The NRC staff is presently pursuing concerns related to downcomer boiling generically. If that review raises any concerns applicable to the LOCA analyses at Ginna that were not considered in this review, then the NRC staff will request the licensee to address these issues consistent with any generic resolution.

LBLOCA Conclusion

The NRC staff reviewed the Westinghouse ASTRUM BE LBLOCA analysis methodology (Reference 73) for application to the Ginna nuclear plant, and the resulting LBLOCA analyses pertaining to the Ginna plant, operating under the proposed EPU conditions. The staff's review confirmed that the licensee and its vendor have processes to assure that the Ginna-specific input parameter values and ranges (where appropriate) that were used to conduct the analyses bounded their as-operated values, that the analyses were conducted within the conditions and limitations of the NRC-approved Westinghouse ASTRUM methodology, and that the results satisfied the requirements of 10 CFR 50.46(b), based on the proposed EPU conditions.

Based on its review of the licensee's BE LOCA analyses, the NRC staff concluded that the Westinghouse ASTRUM methodology (Reference 73), is acceptable for use for Ginna in demonstrating compliance with the requirements of 10 CFR 50.46(b), under the proposed EPU conditions.

c. SBLOCA and Post-LOCA Long-Term Cooling

The NRC staff evaluated the SBLOCA analyses and post-LOCA long-term cooling analyses. The NRC staff's evaluation also included an audit of Westinghouse calculations pertaining to SBLOCA and post-LOCA long-term cooling, upon which certain accident analyses, presented in the licensing report, were based. The NRC staff performed independent calculations, using the RELAP5/MOD3 code, to investigate a spectrum of SBLOCAs, as well as the full range of break sizes to assess the timing for boric acid precipitation for both large and small breaks.

In areas where the licensee and its contractors used NRC-approved methods in performing analyses related to the proposed EPU, the NRC staff reviewed relevant material to assure that the licensee/contractor used the methods consistent with the limitations and restrictions placed on the methods. In addition, the NRC staff considered the effects of the changes in plant operating conditions on the use of these methods to assure that the methods were appropriate for use at the proposed EPU conditions.

The NRC staff's evaluation consisted of reviewing the results of the licensee's analyses of the SBLOCA spectrum performed at 1811 MWt and with a peak linear heat generation rate of 17.5 kw/ft. The NRC staff also reviewed the results of the licensee's post-LOCA long-term cooling analyses to show that the plant's emergency operating procedures (EOPs) could properly deal with and control the build-up of boric acid in the RCS following both LBLOCAs and SBLOCAs. These two areas of review are discussed separately below. The evaluation of the SBLOCA is discussed first.

The NRC staff performed independent calculations to assess the performance of the Ginna NSSS using the RELAP5/MOD3 code. The core power level was assumed to be 1811 MWt, with the hot rod at the peak linear heat generation rate of 17.5 kw/ft. The model included 24 axial cells to track the two-phase level in the core, which also included a hot bundle parallel channel containing the hot rod and the same level of axial detail. The top skewed power shape used in the licensee's NOTRUMP (Reference 23) analyses was also input to the RELAP5/MOD3 code. Both reactor coolant loops in the NRC staff's RELAP5/MOD3 model were represented explicitly in the nodalization of the Ginna NSSS. In the NRC staff's analyses, the ECCS was also modeled as well as the SG atmospheric dump valves (ADVs) and pressurizer PORVs to assess the plant cooldown capabilities and limitations.

<u>SBLOCA</u>

<u>Small-Break Short-Term Behavior and Termination of HHSI Flow</u>

The licensee's original application for small breaks included analysis of the 1.5, 2, and 3-inch diameter breaks in the cold leg at the RCP discharge leg. The worst break in the licensee's analyses was found to be the 2-inch break with a PCT of 1167 EF. The NRC staff issued RAIs questioning the limited nature of the break spectrum and requested analyses of additional breaks, particularly those toward the larger end of the small-break spectrum. The larger breaks were of concern because the Ginna design requires the operators to terminate HHSI flow when re-aligning injection from the RWST to the containment sump to begin the recirculation phase of LOCA mitigation. The licensee's analyses showed a rapid decrease in two-phase level above the top of the core during realignment for the 2- and 3-inch break sizes. However, because the two-phase level was well above the top of the active core, core uncovery did not occur. Analysis of these smaller break sizes suggested to the NRC staff that analyses of the larger breaks would be necessary to show that breaks with potentially less inventory above the top of the core would also not uncover during the realignment period.

The licensee assumed the alignment from the RWST to the containment sump could be performed within about 10 minutes. In responding to NRC staff RAIs, the licensee investigated a larger range of break sizes and provided the results of the 4, 5, 6, 8.75, and 9.75-inch diameter breaks. The analysis of these breaks sizes showed that the PCT for these breaks remained below 1200 EF, due to the high pressure accumulators (714.7 psia) and the high capacity HHSI pumps. In the Westinghouse NOTRUMP analyses of the 6, 8.75, and 9.75-inch breaks, the results showed that the two-phase level receded to very near the top of the core during the 600-second interruption for realignment, then quickly recovered to the hot leg elevation upon re-initiation of HHSI flow. These analyses were performed assuming the break was located on the bottom of the discharge leg.

The NRC staff conducted independent calculations for breaks located on the top of the discharge piping. Uncovery for these breaks is faster because, with the break located on the top of the discharge leg, loop seal clearing does not occur. The filled loop seals during the LOCA increases the steam pressure and decreases the two-phase level in the upper plenum so that there is less inventory above the top of the core relative to the case with the break at the bottom of the discharge leg. With the breaks in the bottom of the leg, the broken loop seal clears of liquid and allows more inventory to accumulate in the upper plenum prior to the realignment interruption. NRC staff calculations showed that, for breaks on the top of the discharge leg in the range of 2 to 6 inches in diameter, core uncovery could result if the realignment required more than 15 minutes. Further, NRC staff calculations showed that the PCTs approached 2200 EF if the alignment required 25 minutes or more. As such, the licensee's ability to complete the realignment within the 10 minutes assumed in its analyses is extremely important to provide reasonable assurance that the plant response to SBLOCAs meets the acceptance criteria of 10 CFR 50.46(b). A review of the timing for realignment of HHSI has been conducted by the NRC staff and is discussed in SE Section 2.11.

The NRC staff RELAP5/MOD3 calculations for SBLOCAs also showed a departure from nucleate boiling, critical heat flux (CHF), condition was achieved in the hot channel causing a first peak during the blowdown. The PCT for these blowdown peaks was calculated by the NRC staff to be between 1500 EF and 1600 EF. The licensee did not calculate a CHF condition occuring because of differences in the timing of the loss of offsite power (LOOP). In the NRC staff calculations, the LOOP was assumed to occur at the worst time following initiation of the LOCA. That is, in the NRC staff model, the LOOP was assumed to occur at the time the reactor trip signal was generated on a low RCS pressure signal. This assumption trips the RCPs, which begin coasting down, while there is a signal delay that delays insertion of the scram rods. As a consequence, there are about 2 to 3 seconds of pump coastdown at full power before the rods have inserted sufficiently to reduce the core power to terminate the rapid clad heat-up. Consistent with the current Ginna licensing basis and the NRC-approved analysis methodology, the licensee assumes no delay between RCP trip and rod insertion.

Since the licensee's analysis was conducted consistent with its licensing basis and the NRC-approved methodology, and the NRC staff's independent analysis showed that there was significant margin to the 10 CFR 50.46(b)(1) 2200 EF PCT acceptance criterion, the NRC staff concluded that the short-term plant response during the HHSI flow phase of SBLOCAs at EPU conditions is acceptable. While the approach for timing of the LOOP has been accepted by the NRC staff previously, the NRC staff plans to review this issue with all vendors to determine if there is a potential generic issue regarding timing for the LOOP following SBLOCAs. Should the NRC staff determine followup actions are required as a result of this issue, the requirements of 10 CFR 50.46(a)(3) provide the regulatory framework under which any plant-specific actions would be taken.

Breaks on the Top of the Discharge Leg

NRC staff independent calculations also showed that breaks located on the top of the discharge leg did not produce more limiting PCTs than the 2-inch break identified as the limiting break by the licensee. Breaks located on the top of the pipe have the potential to be more limiting for plants with deep loop seals (i.e. when the bottom elevation of the loop seal is well below the top elevation of the core), since the steam pressure in the upper plenum during the SBLOCA is higher and depresses the two-phase level into the core.

The NRC staff also noted that the 2-inch break is probably not the worst small break because analysis of integer break sizes produces too coarse of a break spectrum. NRC staff experience has shown that break sizes intermediate to the integer sizes (for example, break sizes between 2 and 3 inches, and between 3 and 4 inches) can result in PCT increases by as much as 150 EF. However, the NRC staff concluded that, since the SBLOCA PCTs are very low due to the high capacity of the HHSI pump relative to the core power level (which sets the core steaming rate during the event) and the high pressure of the accumulators (i.e. 714.7 psia), further analyses of breaks between 2 and 3 inches and 3 and 4 inches was not warranted to support the proposed Ginna EPU.

SBLOCA Conclusion

Based on the appropriate application by the licensee of NRC-approved methodologies to analyze Ginna's response to SBLOCAs and the NRC staff's independent analyses, the NRC staff concludes that operation of Ginna at EPU conditions is acceptable in being able to mitigate the consequences of SBLOCAs. Therefore, the NRC staff concludes it has reasonable assurance that for SBLOCAs the acceptance criteria of 10 CFR 50.46(b)(1), (2), and (3) related to PCT, local oxidation, and hydrogen generation, respectively, are satisfied for Ginna at EPU conditions.

Post-LOCA Long-Term Cooling

Large Break Behavior

The NRC staff performed assessments of the timing for boric acid precipitation following LBLOCAs using its models developed for other plant power uprate reviews. NRC staff calculations using these models showed that without a core flushing flow, precipitation can occur in 4.3 hrs compared to the 6.2-hr time to precipitation computed by the licensee. The staff utilized the same boundary conditions as the licensee and included:

- the mixing volume includes 1/2 of the lower plenum, the core, and the portion of the upper plenum below the bottom elevation of the hot legs;
- the boron precipitation limit is assumed to be 29.27 weight percent (wt%) at 14.7 psia;
- the decay heat curve uses the 1971 ANS Standard with a 1.2 multiplier; and

- mixing into the lower plenum does not begin until the core liquid density, with boric acid, exceeds the density of the water in the lower plenum at the RWST temperature of 120 EF. Mixing does not begin in the lower plenum until the concentration in the core reaches 12.3 wt% boric acid.

The differences in precipitation timing are due to the licensee's assumption that the boric acid build-up does not begin until 24 minutes into the LOCA. NRC staff calculations showed that with the 24-minute delay, the 29.27 wt% boron precipitation limit would not be achieved until about 5.8 hrs, which is reasonably close to the licensee's time of 6.2 hrs. The NRC staff questioned the delay and requested further analysis and justification from the licensee. In response to the NRC staff's questions and concerns, the licensee performed a WCOBRA/TRAC analysis of the LBLOCA, with Appendix K "type assumptions" and showed that, within 300 seconds following opening of the break, there is sufficient flushing flow to terminate the build-up of boric acid in the core. In fact, at 300 seconds, the HHSI flow into the RCS exceeded the boil-off in the core by 20 lbs/sec. At 300 seconds, the boric acid concentration was about 6.4 wt%. The large flushing flow, which would continue to increase over the first 24 minutes, would reduce the boric acid concentration to very near the source concentration.

It is important to note that the limiting large break in this evaluation for Ginna is a hot-leg break. This is the worst break for boric acid precipitation because HHSI is terminated upon depletion of the RWST inventory, which for a LBLOCA occurs at about 24 minutes into the event. The HHSI pumps must be turned off and re-aligned to take suction from the containment sump to start the recirculation phase of the LOCA mitigation. It should be noted that Ginna is unique in that the design does not enable the operators to switch the cold-side injection to simultaneous hot- and cold-side injection. Rather, with the UPI system design, it must be shown that the RCS pressure can be reduced to a value below 140 psia to enable the RHR low pressure injection to provide water to the upper plenum, simultaneously with the HHSI injecting water into the cold legs. Since HHSI is terminated upon drainage of the RWST, analyses of the precipitation timing must be performed to identify the time frame within which HHSI must be re-instituted to flush the boric acid from the system.

The operators must realign HHSI prior to the boron precipitation limit being exceeded. For Ginna, this switch time is set at 5.5 hrs, or just before the 6.2-hr precipitation time calculated by the licensee. At 300 seconds, the COBRA/TRAC calculation shows the liquid flow out the break to be in excess of 50 lbs/sec, with an HHSI cold leg injection rate of about 80 lb/sec. The NRC staff considers this to be a sufficient flushing flow to reduce the initial build-up and reduce the concentrations to the source concentration prior to termination of HHSI at 24 minutes. It is noted that cold-leg breaks are not limiting for the Ginna NSSS since the lower pressure injection into the upper plenum would provide a flushing flow once RCS pressure decreased below 140 psia.

The NRC staff concurs that the LBLOCA analysis for boric acid precipitation timing provides sufficient time for the operators to realign HHSI to control the boric acid build-up for all large breaks that depressurize below the shutoff head of the RHR low pressure SI pumps. Delaying the time to initiate the build-up to 24 minutes following the initiation of the break is justified based on the WCOBRA/TRAC LBLOCA calculation. Smaller breaks that do not depressurize below the shutoff head of the low pressure pump require additional operator actions to control the boric acid build-up and prevent precipitation. Small breaks and the attendant operator actions are discussed below.

Small Break Behavior

In the licensing report, the licensee did not initially provide sufficient information nor analyses to demonstrate boric acid could be controlled following SBLOCAs because the RCS pressure could remain above the shutoff head of the RHR low pressure SI pump for many hours. Several sets of RAIs were issued discussing the need for analyses of the entire small-break spectrum with identification of all the operator actions and precautions needed to successfully accomplish this function. Since RCS pressure remains above 140 psia for hours for certain SBLOCAs, the NRC staff required analysis of the break spectrum to show that the plant could be cooled down below the shutoff head of the RHR pump prior to reaching the boron precipitation limit. For the very small breaks, where cooldown to these low pressures may be difficult, the analysis must show the RCS refills and disperses the boric acid throughout the RCS, or another approach to preclude boron precipitation needed to be identified and justified. The NRC staff also expressed concerns in RAIs for the need to update the EOPs, since the EOPs did not contain nor identify the equipment and timing for the operator actions necessary for cooling down the RCS to initiate RHR low pressure injection to control boric acid following SBLOCAs. In response to the NRC staff concerns and need for additional justification and analysis for small breaks, the licensee performed analyses of the break spectrum to demonstrate boric acid can be controlled for all break sizes. The results of the licensee's NOTRUMP SBLOCA analyses can be summarized as follows:

- For breaks of 1.0 ft^2, 0.8 ft^2, 0.6 ft^2, and 8.0 inches, 6.0 inches, and 4.0 inches in diameter, the break size is sufficient to depressurize the RCS to enable RHR low pressure SI into the upper plenum. No new operator actions were identified or required. The only operator action was to re-start HHSI into the cold legs, taking suction from the containment sump, no later than 5.5 hrs similar to actions required in response to LBLOCAs.

- For 2.0, 1.8, 1.4, 1.3, 1.2 , 1.1, and 1.0 inch diameter breaks, the operators must depressurize the RCS to the RHR cut-in pressure (below about 140 psia) before the boron precipitation limit is reached. To accomplish this requires the operator to open both ADVs no later than 1 hour into the event. This operator action reduces RCS pressure below 140 psia within 5 to 6 hours.

- For the 1.0, 0.9, and 0.8 inch diameter breaks, single phase natural circulation is lost but regained before the precipitation limit is reached. Therefore, no new operator actions were identified or required to prevent boron precipitation from occurring.

- For the 0.7, 0.6, and 0.5 inch diameter breaks, natural circulation is not lost and no new operator actions were identified or required to prevent boron precipitation from occurring.

- The 0.375-inch diameter break is within the capacity of the charging pumps and is considered a leak, not an SBLOCA.

These results can be summarized in the following manner:

- For breaks 1.0 ft^2 down to the 4-inch diameter break analyses show that precipitation will not occur before 6.2 hrs and reinstating high pressure injection at 5.5 hrs will control the boric acid buildup and preclude boron precipitation from occurring.

- For breaks of 2.0 inches down to 1.0 inch in diameter, analyses show that initiating a cooldown with the ADVs no later than 1 hour into the event will reduce RCS pressure below the shutoff head of the RHR low pressure SI injection pumps prior to boron precipitation occurring.

- For breaks less than 1.0 inch in diameter analyses show that single phase natural circulation will disperse the boric acid throughout the RCS, reducing the concentration in the vessel to very low values prior to reaching the RHR cut-in pressure of 140 psia.

<u>Enhanced Boron Precipitation Controls</u>

Because operator actions are required to control boric acid precipitation following all LOCAs, changes were recommended to the plant EOPs to assure boric acid is controlled and precipitation is prevented during a LOCA. The NRC staff requested the licensee include the key operator actions to initiate a timely cooldown of the RCS to assure actuation of the RHR low pressure SI pumps which, in combination with the HHSI pumps, provide a flushing flow through the core for all break sizes that do not refill with ECCS injection water.

With a LOOP, it is necessary to initiate a cooldown with the SG ADVs. The NRC staff raised a question about boron precipitation impacts should one of the ADVs fail to open. The NRC staff calculations also showed that the RCS can boil for extended periods during the cooldown following an SBLOCA. In these situations, the NRC staff requested the Ginna EOPs be modified to alert the operators not to suddenly cool the RCS should boiling extend for many hours.

As a result of NRC staff calculations for SBLOCAs, the NRC staff raised questions regarding the failure of an ADV to open and the possible need for the PORVs to be opened to ensure a timely cooldown. This condition is not part of the current licensing basis for Ginna. The NRC staff's RELAP5/MOD3 calculations showed that the RCS pressure cannot be reduced below about 120 psia (i.e. the pressure required for sufficient RHR low pressure injection flow to begin flushing the core) for at least 8.3 hrs when 2 ADVs and 2 PORVs are opened after 1 hour following the opening of a 0.0125 ft^2 cold leg break.

The NRC staff calculations suggest that with the RCS boiling for more than 8 hours, large amounts of boric acid (i.e. in excess of the 29.3 wt% boron precipitation limit at 14.7 psia) can accumulate in the vessel. While the RCS pressure remains above 120 psia, the RCS temperature is sufficiently high to keep the boric acid in solution. As such, the NRC staff expressed concerns that, should the operators regain power to more rapidly depressurize the RCS, boron precipitation could inadvertently occur. Based on RAIs and discussions with the licensee, the licensee agreed to enhance its EOPs to provide guidance to caution the operators not to suddenly depressurize the RCS should there be limited cooldown capability followed by a later restoration of depressurization equipment. The licensee will modify the EOPs to instruct the operators not to exceed the 100 EF/hr cooldown limit following an SBLOCA. The EOPs will also be updated to alert the operators to use the PORVs to cool down should one of the ADVs fail to open. While the NRC staff finds that one ADV may not depressurize the RCS to120 psia for small breaks for many hours, as noted previously, the high RCS coolant temperature will maintain the boric acid in solution. The proposed enhancements to the EOPs provide the NRC staff with reasonable assurance that there are adequate controls in place that will prevent the operators from causing an inadvertent precipitation by limiting the depressurization rate during the long term cooling phase of SBLOCA mitigation in the event boiling persist for extended periods with the RCS pressure above 120 psia.

The NRC staff also noted that the Ginna NSSS has boric acid tanks with very high boric acid concentrations. In the unlikely event the operators are charging the RCS with boric acid from these tanks prior to the LOCA, the NRC staff also requested the EOPs include a caution for the operators to immediately terminate injection from these tanks following a LOCA. Injection from these tanks would cause the boric acid content in the RCS to increase rapidly if the injection is not terminated. The NRC staff notes that consistent with the Ginna design, boric acid injection from the boric acid tanks is automatically terminated following an SI signal. Since this signal may not occur for some time following SBLOCAs, an undesirable amount to boric acid could be injected into the RCS. As an enhancement, the licensee will include a caution in the EOPs that would limit the injection of this high concentrate boric acid.

Long-Term Cooling Conclusion

The NRC staff considers the licensee's analyses, in combination with the aforementioned operator actions, to be an acceptable approach for controlling boric acid precipitation for the Ginna NSSS at the proposed EPU operating conditions. Based on its review, the NRC staff finds the analyses, given the noted operator actions and EOP changes to facilitate the successful control of boric acid following all LOCAs, provides reasonable assurance that the long-term cooling requirements of 10 CFR 50.46(b)(5) are satisfied for Ginna under EPU conditions.

Conclusion

The NRC staff reviewed the Westinghouse SBLOCA and post-LOCA long-term cooling analyses for application to the Ginna NSSS operating under the proposed EPU conditions. The NRC staff's review confirmed that the licensee and its vendor have processes to assure that the Ginna-specific input parameter values and operator action times (where appropriate) that were used to conduct the analyses will assure that 10 CFR 50.46 limits are not exceeded and long-term cooling can be assured for all break sizes by providing the means to remove decay heat for extended periods, while also preventing the precipitation of boric acid for all break sizes and locations. Furthermore, the NRC staff finds that the analyses were conducted within the conditions and limitations of the NRC-approved Westinghouse NOTRUMP SBLOCA methodology, and that the results satisfied the requirements of 10 CFR 50.46(b), based on the proposed EPU conditions. The staff notes that the procedures for assuring boric acid control for all breaks for the Ginna NSSS are unique to this system and finds the vendor and licensee approach to be a conservative and acceptable approach for demonstrating core cooling during the long term for all break sizes.

The NRC staff notes that, to support the acceptability of the Ginna NSSS operation at EPU conditions, the licensee has agreed to include the following changes and enhancements to the EOPs to assure successful post-LOCA long-term cooling for all break sizes.

1. The EOPs will instruct the operators to re-align HHSI to the sump no later than 5.5 hrs post-LOCA.

2. The operators will initiate a cooldown no later than 1 hour into the event to reduce RCS pressure to values below 140 psia.

3. Both ADVs are to be opened with a limit on the cooldown not to exceed 100 EF/hr.

4. If an ADV fails to open, then both PORVs should be actuated.

5. The re-alignment of HHSI to take suction from the sump should be performed in no more than 10 minutes.

6. If high concentrate boric acid is being injected into the RCS, termination during any LOCA should be immediate.

7. The operators should be especially cautioned to not suddenly depressurize the RCS should boiling persist for more than 6 hours. Adherence to the 100 EF/hr cooldown limit should be noted to preclude an inadvertent precipitation.

Based on its review of the licensee's SBLOCA and post-LOCA long-tem cooling analyses, the NRC staff concludes that the Westinghouse NOTRUMP SBLOCA methodology and post-LOCA long-term cooling evaluation, are acceptable for use at Ginna in demonstrating compliance with the requirements of 10 CFR 50.46(b) under the proposed EPU conditions.

2.8.5.7 Anticipated Transients Without Scram

Regulatory Evaluation

Anticipated transients without scram (ATWS) is defined as an AOO followed by the failure of the reactor portion of the protection system specified in GDC 20. The regulation at 10 CFR 50.62 requires that each PWR must have equipment that is diverse from the reactor trip system to automatically initiate the auxiliary (or emergency) feedwater system and initiate a turbine trip under conditions indicative of an ATWS. This equipment must perform its function in a reliable manner and be independent from the existing reactor trip system.

The NRC staff's review was conducted to ensure that (1) the above requirements are met, and (2) the setpoints for the ATWS mitigating system actuation circuitry (AMSAC) remain valid for the proposed EPU. In addition, the NRC staff verified that the consequences of an ATWS are acceptable. The acceptance criterion is that the peak primary system pressure should not exceed the ASME Service Level C limit of 3200 psig. The peak ATWS pressure is primarily a function of the moderator temperature coefficient (MTC) and the primary system relief capacity. The NRC staff reviewed (1) the limiting event determination, (2) the sequence of events, (3) the analytical model and its applicability, (4) the values of parameters used in the analytical model, and (5) the results of the analyses. Review guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

Ginna has installed AMSAC (described in Chapter 7.6.2 of the UFSAR), as per the requirements of 10 CFR 50.62. Ginna was covered by a set of generic ATWS analyses, performed by Westinghouse, in 1974, for plants equipped with Westinghouse series 44 SGs (Reference 70). These analyses were updated, 5 years later (Reference 71). In 1996, Ginna replaced its SGs with B&WC SGs, and justified the change, with respect to ATWS, with an SE, performed under the provisions of 10 CFR 50.59.

The proposed EPU, with its 16.8% increase in power level, is expected to result in higher peak pressures during ATWS events. Therefore, Ginna performed new ATWS analyses, at the EPU power level, and with the B&WC SGs. The licensee concluded that the acceptance limit of 3200 psig was met; but did not provide the supporting transient analysis results. These were requested by the staff, and submitted by the licensee, along with details of the analyses, such as codes used, code input values, and assumptions.

The limiting ATWS event for Ginna is the loss of feedwater without scram. This event was analyzed with the LOFTRAN (Reference 29) code, which is approved by the NRC for use in ATWS analyses. LOFTRAN has been used by Westinghouse for ATWS analyses since 1974. Since LOFTRAN uses a simple SG model, with a one-node shell side volume, it is necessary to employ the NOTRUMP (Reference 60) SG thermal-hydraulic computer code to calculate the secondary side SG water mass transient during the ATWS. The SG shell side mass, as a function or shell side water level, is then input to LOFTRAN, where it is used to calculate the rate of heat transfer degradation in the SGs, as the water level falls below the top of the tubes. The peak RCS pressure attained during an ATWS is influenced by the initial power level, the rate of heat sink loss, and the MTC. Without the reactor trip, the only core shutdown mechanism available is the negative reactivity feedback generated by the core heatup, as the heat sink is lost. It is conservative to use a small MTC.

The maximum RCS pressure, predicted by the LONF ATWS analysis, is 3193 psig. Therefore, the ATWS acceptance criterion, the ASME Service Level C limit of 3200 psig, was satisfied. The staff finds that Ginna would continue to meet ATWS acceptance criteria, under the proposed EPU conditions, as equipped with AMSAC and Babcock & Wilcox SGs.

Conclusion

The NRC staff has reviewed the information submitted by the licensee related to ATWS and concludes that the licensee has adequately accounted for the effects of the proposed EPU on ATWS. The NRC staff concludes that the licensee has demonstrated that the AMSAC will continue to meet the requirements of 10 CFR 50.62 following implementation of the proposed EPU. The Ginna plant is not required by 10 CFR 50.62 to have a DSS. The licensee has demonstrated, as explained above, that the peak primary system pressure following an ATWS event will remain below the acceptance limit of 3200 psig. Therefore, the NRC staff finds the proposed EPU acceptable with respect to ATWS.

2.8.6 New Fuel and Spent Fuel Fuel Storage

As part of its analysis for operation at EPU levels, the licensee reviewed its ability to store both the new and spent fuel at Ginna. As part of its EPU application, Ginna is transitioning to the Westinghouse 422V+ fuel assembly design. Differences between the current fuel assemblies employed at Ginna and this new fuel design necessitated a review of the criticality aspects governing its safe storage both prior to and following irradiation in the reactor.

Regulatory Evaluation

Nuclear reactor plants include facilities for the storage of new fuel. The quantity of new fuel to be stored varies from plant to plant depending upon the specific design of the plant and the individual refueling needs. The NRC staff's review covered the ability of the storage facilities to maintain the new fuel in a subcritical array during all credible storage conditions. The review focused on the effect of changes in fuel design on the analyses for the new fuel storage facilities. Nuclear reactor plants also include storage facilities for the wet storage of spent fuel assemblies. The safety function of the spent fuel pool and storage racks is to maintain the spent fuel assemblies in a safe and subcritical array during all credible storage conditions and to provide a safe means of loading the assemblies into shipping casks.

The NRC's acceptance criteria are based on GDC 62, "Prevention of criticality in fuel storage and handling," insofar as it requires the prevention of criticality in fuel storage systems by physical systems or processes, preferably utilizing geometrically safe configurations. According to GDC 62, the licensee must limit the potential for criticality in the fuel handling and storage system by physical systems or processes. The staff reviewed the amendment request to ensure that the licensee complied with GDC 62. Specific review criteria are contained in SRP Sections 9.1.1 and 9.1.2.

The NRC staff reviewed the Ginna new and spent fuel storage licensing bases, including any previously NRC-approved licensing actions, to determine the appropriate regulatory criteria for reviewing fuel storage and handling under the proposed EPU conditions. On July 16, 1997, the NRC issued Ginna an exemption to the requirements of 10 CFR 70.24 for criticality monitors in the spent fuel pool (Reference 66). Subsequently, on July 30, 1998, the NRC issued Amendment No. 72 to Ginna's operating license to revise the criticality licensing basis of the Ginna spent fuel pool (Reference 67). The TS changes approved in that amendment were based on maintaining the effective multiplication factor (k_{eff}) less than 0.95 with full density unborated water. Amendment No. 72 invalidated the previous 10 CFR 70.24 exemption because it resulted in a change to the licensing basis. More recently, on December 7, 2000, the NRC issued Amendment No. 79 to Ginna's operating license to revise the criticality licensing basis of the Ginna spent fuel storage racks (Reference 68). In Amendment No. 79, the NRC approved a change in the criticality safety criteria to permit a credit for soluble boron present in the spent fuel pool. The licensee's current licensing basis requires that the spent fuel storage racks be designed and maintained with a k_{eff} less than 1.0 if flooded with unborated water and less than or equal to 0.95 if flooded with borated water.

On November 12, 1998, the NRC issued 10 CFR 50.68, "Criticality accident requirements." 10 CFR 50.68(a) requires that "Each holder of a construction permit or operating license for a nuclear power reactor issued under this part,...shall comply with either 10 CFR 70.24 of this chapter or the requirements of paragraph (b) of this section." On November 3, 2005, the licensee provided additional information to clarify its licensing basis with regard to the safe storage of new and spent fuel in the Ginna spent fuel pool (Reference 26). In its supplement, the licensee provided a detailed description of how it satisfied each of the eight criteria in 10 CFR 50.68(b). The licensee's response demonstrates that its current spent fuel pool design satisfies NRC regulations governing the safe handling and storage of new and irradiated fuel in the spent fuel pool. In addition, the licensee stated that, as required by 10 CFR 50.68(b)(8), it will update the UFSAR in accordance with 10 CFR 50.71(e) to reflect compliance with 10 CFR 50.68.

Technical Evaluation

For the proposed EPU conditions, the licensee performed a detailed review of the current licensing basis criticality analyses governing new and spent fuel storage at Ginna. The licensee determined that the change in fuel design to the Westinghouse 422V+ fuel assembly necessitated an evaluation of the key assumptions and inputs used in the current criticality analyses.

For the storage of irradiated fuel in the spent fuel pool, the licensee determined that the design basis fuel assembly used in the current criticality analysis licensing basis was the Westinghouse Standard fuel assembly. During its review the licensee determined that conservative assumptions for fuel design parameters such as fuel pellet diameter and stack height were used in performing the criticality analyses for spent fuel assemblies. The licensee compared these conservative assumptions to the nominal design parameters and associated manufacturing tolerances for the new Westinghouse 422V+ fuel assemblies to be used in subsequent EPU reloads. The licensee confirmed that the design parameter assumptions used in the licensing basis criticality analyses bound those of the new Westinghouse 422V+ fuel assemblies. Therefore, the licensee concluded, and the NRC staff agrees, that the current criticality analyses for spent fuel storage in the Ginna spent fuel pool will remain bounding for future fuel assemblies irradiated under EPU operating conditions.

With regard to the storage of new fuel assemblies in the dry new fuel storage building, the licensee performed a similar analysis for the current criticality analysis licensing basis. The licensee determined that the design basis fuel assembly in the current analysis is based on a Westinghouse OFA. The licensee reviewed the assumptions for key design parameters used in performing the criticality analyses for the Westinghouse OFAs and compared them to the new Westinghouse 422V+ fuel assemblies. The licensee determined that two of the fuel design parameters, the fuel pellet diameter and the stack height, for the new Westinghouse 422V+ fuel assembly were not bounded by assumptions used in the current new fuel criticality analysis licensing basis. The current licensing basis for the new fuel storage racks states that the k_{eff} must be maintained less than or equal to 0.98 under optimum moderation conditions. Due to a large center-to-center spacing between fuel assemblies in the new fuel storage racks, the calculated k_{eff} of the Westinghouse OFA fuel assemblies in the current licensing basis is only 0.667. This demonstrates that there is considerable margin to the NRC's regulatory and safety limits. In its RAI response, the licensee described the differences between the two fuel assemblies. The licensee's evaluation demonstrates that the differences are minor and that even if new criticality analyses were performed, it is extremely unlikely that the calculated k_{eff} would increase substantially. Therefore, the staff finds that the licensee's current criticality analysis licensing basis for new fuel storage at Ginna contains sufficient margin to NRC regulatory and safety limits to account for minor differences in the fuel design parameters and that the NRC staff has reasonable assurance that the licensee will continue to comply with applicable NRC regulations governing the safe storage of new fuel at Ginna.

Conclusion

The licensee performed a detailed review of the new and spent fuel storage criticality analyses that govern the safe storage and handling of fuel at Ginna. The licensee has provided sufficient information to demonstrate that NRC regulations (i.e., GDC 62 and 10 CFR 50.68) will continue to be met under uprated power conditions. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the new and spent fuel storage.

2.9 Source Terms and Radiological Consequences Analyses

2.9.1 Source Terms for Radwaste Systems Analyses

Regulatory Evaluation

The NRC staff reviewed the radioactive source term associated with EPUs to ensure the adequacy of the sources of radioactivity used by the licensee as input to calculations to verify that the radioactive waste management systems have adequate capacity for the treatment of radioactive liquid and gaseous wastes. The NRC staff's review included the parameters used to determine (1) the concentration of each radionuclide in the reactor coolant, (2) the fraction of fission product activity released to the reactor coolant, (3) concentrations of all radionuclides other than fission products in the reactor coolant, (4) leakage rates and associated fluid activity of all potentially radioactive water and steam systems, and (5) potential sources of radioactive materials in effluents that are not considered in the Ginna UFSAR related to liquid waste management systems and gaseous waste management systems. The NRC's acceptance criteria for source terms are based on (1) 10 CFR Part 20, in so far as it establishes requirements for radioactivity in liquid and gaseous effluents released to unrestricted areas; (2) 10 CFR Part 50, Appendix I, insofar as it establishes numerical guides for design objectives and limiting conditions for operation to meet the "as low as is reasonably achievable" criterion; and (3) GDC 60, in so far as it requires that the plant design include means to control the release of radioactive effluents. Specific review criteria are contained in SRP Section 11.1.

Technical Evaluation

The core isotopic inventory is a function of the core power level and reactor coolant activity concentrations are a function of the core power level, leakage from the fuel, radioactive decay and removal by coolant purification systems. The licensee recalculated the maximum reactor coolant fission product activity concentration assuming 1% failed fuel, and the expected reactor coolant concentration source terms for radioactive liquid and gaseous effluents for the higher proposed reactor power. The licensee also calculated the core isotopic inventory for the higher proposed reactor power for use in accident dose and equipment qualification dose evaluations.

The licensee calculated the maximum reactor coolant fission product activity concentration assuming 1% failed fuel using the methods and models outlined in Section 11.1.2 of the Ginna UFSAR. The calculations assumed operation at a core power of 1811 MWt for 575 effective full-power days (EFPD). The assumed core power of 1811 MWt includes a power measurement uncertainty of 2%. Other inputs and assumptions were unchanged from the original Ginna design basis as specified in UFSAR Section 11.1. The NRC staff finds that the licensee has used the appropriate core power assumptions for the EPU. The NRC staff also finds that the EPU would not impact any of the other inputs and assumptions to the maximum coolant concentration calculations, so continued use of the current UFSAR values is acceptable. The staff finds that the licensee has appropriately calculated the maximum reactor coolant fission product activity concentration for the EPU.

The licensee calculated the average reactor coolant fission product activity concentration using the ANSI/ANS-18.1-1999 methodology. ANSI/ANS-18.1-1999 is an acceptable methodology to the NRC staff. Application of this standard is consistent with the methodology included in Revision 1 of the gaseous and liquid effluent (GALE) code that is considered by the NRC in its review of expected plant radioactive effluents for all light-water reactor (LWR) plants, adjusted for the increase in thermal power by 2% to bound measurement uncertainty. Normal sources for Ginna Station are established by appropriate scaling by thermal power and other pertinent EPU parameters as outlined in the standard.

Tritium Sources

The total releases to the reactor coolant during an EPU fuel cycle were compared to the values currently identified in Ginna UFSAR Section 9.3.4.4.9. Both the “design” and “expected” values of total tritium in the coolant associated with the EPU are lower than the original annual production value identified in the Ginna UFSAR Section 9.3 (Table 9.3-11c). The lowering of total tritium for the EPU condition is attributable to the difference in release fraction of tritium from the core. For the existing, non-EPU conditions, 30% of the tritium generated in the core is assumed to be released to the coolant. This assumption was based on analysis made from stainless steel cores. It has been updated for the EPU based on more recent operating plant data, including NRC contractor report NUREG/CR -2907, to a conservative “design” value of 10%, and the more realistic “expected” value of 2%.

The staff finds this acceptable, since the tritium sources associated with the EPU remain substantially below the original design basis production values, and concludes that the EPU will not impact the current situation.

As is discussed in Sections 2.5 and 2.10 of this SE, the licensee provided calculations to show that Ginna would continue to meet its design basis by meeting the requirements of 10 CFR Part 20, 10 CFR Part 50, Appendix I, and GDC 60 with EPU source terms.

Conclusion

The NRC staff has reviewed the radioactive source term associated with the proposed EPU and concludes that the proposed parameters, resultant composition and quantity of radionuclides are appropriate for the evaluation of the radioactive waste management systems. The NRC staff further concludes that the proposed radioactive source term meets the requirements of 10 CFR Part 20, 10 CFR Part 50, Appendix I, and GDC 60. Therefore, the NRC staff finds the proposed EPU acceptable with respect to source terms.

2.9.2 Radiological Consequences Analyses Using Alternative Source Terms

Regulatory Evaluation

The NRC staff reviewed the DBA radiological consequences analyses submitted to support the EPU. The radiological consequences analyses reviewed are the LOCA, fuel handling accident (FHA), control rod ejection accident (REA), MSLB, SG tube rupture (SGTR), locked-rotor accident (LRA), and tornado missile accident (TMA). The NRC staff's review for each accident analysis included (1) the sequence of events; and (2) models, assumptions, and values of parameter inputs used by the licensee for the calculation of the total effective dose equivalent (TEDE). The NRC's acceptance criteria for radiological consequences analyses using an alternate source term are based on (1) 10 CFR 50.67, insofar as it sets standards for radiological consequences of a postulated accident, and (2) GDC 19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem TEDE, as defined in 10 CFR 50.2, for the duration of the accident. Specific review criteria are contained in SRP Section 15.0.1, and regulatory guidance on evaluating DBAs is given in RG 1.183.

Technical Evaluation

The NRC staff reviewed the regulatory and technical analyses, as related to the radiological consequences of DBAs, performed by Ginna in support of its proposed license amendment. The staff reviewed the assumptions, inputs, and methods used by Ginna to assess the impact of the requested power uprate on the radiological consequences of DBAs. The staff also has performed selected independent confirmatory radiological consequence dose calculations to verify the licensee's analysis results. The findings of this SE input are based on the descriptions of the licensee's analyses and other supporting information docketed by Ginna.

The licensee re-analyzed the radiological consequences for the following seven DBAs to account for the uprated power:

- Loss-of-coolant accident (LOCA)
- Fuel handling accident (FHA)
- Main steam line break (MSLB)
- SG tube rupture (SGTR)
- Reactor coolant pump locked rotor accident (LRA)
- Rod ejection accident (REA)
- Tornado missile accident (TMA)

These DBAs were previously analyzed in the licensing submittal to Amendment No. 87, dated February 25, 2005 (Reference 77) to the Ginna license, which implemented an alternative source term in accordance with 10 CFR 50.67. These previous radiological analyses used the analytical methods and assumptions outlined in RG 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors." The revised analyses submitted by the licensee to support the current proposed power uprate to 1775 MWt are substantially the same as the previously approved analyses, with changes as discussed below. In all cases, the revised core and coolant inventories are based on the uprated power operation at 1775 MWt increased by 2% to 1811 MWt to account for power measurement uncertainty.

a. LOCA

The LOCA considered is a double-ended rupture of a RCS pipe. The activity from the core is released to the containment and then to the environment by containment leakage or leakage from the ECCS as it re-circulates sump solution outside the containment. The staff has reviewed the licensee's analyses for the following two potential fission product release pathways:

(1) primary containment leakage, and

(2) leakage from ECCSs outside containment.

Any potential back leakage into the isolated reactor water storage tank (RWST) during the containment sump water recirculation following a LOCA is included in the leakage pathway from the ECCS outside containment in (2) above.

1. LOCA Containment Leakage

The current Ginna design basis containment leak rate specified in the UFSAR is 0.2% by volume per day (% per day). For the radiological consequence analysis, this rate is decreased to 0.1% per day after 24 hours following a LOCA for the duration of the accident (30 days), consistent with the guideline provided in RG 1.183. The licensee has not proposed to change the design basis TS containment leak rate.

The fission products in the containment atmosphere following the postulated LOCA at Ginna are mitigated by (1) natural deposition of fission products in aerosol form, (2) the CS System (CSS), and (3) the Containment Recirculation Cooling and Filtration System (CRCFS). The licensee has conservatively neglected natural deposition of fission products in aerosol form in the containment and therefore, excluded any credit for the removal of fission products in aerosol form by natural deposition in the radiological consequence re-analyses. The radiological consequence analyses performed by the licensee showed that Ginna would still meet the relevant dose criteria specified in 10 CFR 50.67 without any credit for removing fission products by natural deposition processes in the containment.

The CSS is an engineered safety feature (ESF) system. In conjunction with the CRCFS, it is designed to provide containment cooling and fission product removal in the containment following the postulated LOCA. The CSS consists of two trains. Each train consists of a pump, two spray headers, and associated valves. Each train of the CSS is independently capable of delivering 1,300 gallons per minute (gpm) of borated water from the RWST into 78% of the containment atmosphere. The spray pumps are automatically started whenever the coincidence of two sets of two-out-of-three high containment pressure signals occurs. The licensee assumed that one out of two spray pumps starts taking suction initially from the RWST and also initiates building spray through two spray headers until the water in the RWST reaches a pre-set low level at 52 minutes after the accident. The licensee assumed that spray flow is initiated within 80 seconds from the initiation of the postulated LOCA. These CSS design and operational features are not affected by the EPU.

Sixty minutes into the accident, the spray pump suction is transferred manually to the containment sump and the spray water from the containment sump is re-circulated until the spray operation is terminated at 30 days. The licensee conservatively did not take any credit for iodine removal by the CS during the re-circulation phase of CS operation. The licensee used the guidance provided in RG 1.183 to determine the removal rates (a factor of 20 per hour for elemental iodine and a factor of 3.5 per hour for iodine in particulate form) by the CSS during the initial spray water delivery into the containment atmosphere from the RWST. The staff finds that these removal rates are acceptable. The major parameters and assumptions used by the licensee, including the spray removal rates, are listed in Table 2.9.2-1.

The CRCFS is designed to remove heat at the design basis rate from the containment atmosphere depressurizing the containment and it also removes fission products following a LOCA. The CRCFS consists of four units, each including, among others, charcoal and high-efficiency particulate air filters. Each unit has 30,000 cfm flow capacity. During normal plant operation, the charcoal filters are by-passed. Two of the four units are required during the post-accident period. In the event of a LOCA, the air flow would be directed through the charcoal filters. However, in this license amendment request, the licensee requested to delete the requirements for the CRCFS charcoal filters from the Ginna TSs. The radiological consequence analyses performed by the licensee showed that Ginna would still meet the relevant dose criteria specified in 10 CFR 50.67 without any credit for removing iodine by the charcoal filters in the CRCFS.

2. Post-LOCA Leakage From Engineered Safety Features Outside Containment

During the initial phases of a LOCA, safety injection and CS systems draw borated water from the RWST. Sixty minutes after the start of the event, these systems start to draw water from the containment sump instead. This recirculation flow causes contaminated sump water to be circulated through piping and components outside of the containment, where small amounts of system leakage could provide a path for the release of radionuclides to the environment. The licensee conservatively assumed a leakage rate of 4 gallons per hour (gph) which is two times the TS limit value of two gph. This ECCS leakage rate assumption is consistent with the guideline provided in RG 1.183. The licensee stated that the ECCS leakage assumption includes any potential back leakage into the RWST during the containment sump water recirculation following a LOCA.

The licensee conservatively assumed that all of the radioiodines released from the fuel are instantaneously moved to the containment sump water and noble gases are assumed to remain in the containment atmosphere. Consistent with the guidance provided in RG 1.183, the licensee assumed that (1) since the containment sump pH is maintained greater than 7, the radioiodine in the sump solution is in nonvolatile iodide or iodate form and, as such, the chemical form of radioiodine in the sump water at the time of recirculation, is 97% elemental iodine and 3% organic, and (2) the total iodine in leaked fluid is assumed to become airborne and released to the environment, via the back-draft damper’s louver on the north wall of the auxiliary building, for 30 days after the start of recirculation. This release point has the most conservative atmospheric dispersion factor for the control room.

By Amendment No. 87, the current licensing basis was changed to assume that a decreasing amount over time (from 7% to 2%) of the radioiodines contained in the ECCS leakage would be released to the auxiliary building atmosphere. Appendix A to RG 1.183 states that the amount of iodine that becomes airborne from the leaked ECCS fluid should be assumed to be 10% of the total iodine activity in the leaked fluid, unless a smaller amount can be justified based on the actual sump pH history and ventilation rate.

The licensee calculated and proposed that the amount of iodine that becomes airborne could be assumed to range from 5% at the start of the containment sump water recirculation and gradually decrease to 2% as a function of time for the duration of the 30-day accident period. For this estimate, the licensee used a constant enthalpy equation based on Ginna specific temperature and pressure for the sump water circulating outside the containment following a LOCA. The staff finds these values are reasonable and acceptable based on the licensee using the same methodology previously accepted by the staff in Ginna's Control Room Emergency Air Treatment/AST amendment (Amendment No. 87, issued February 25, 2005). The staff believes that the revised 5% to 2% ECCS leakage airborne iodine values are representative of iodine behavior and transport at Ginna following the LOCA.

The NRC staff's acceptance of the amount of iodine that becomes airborne is based on the licensee's constant enthalpy calculation based on Ginna specific sump water temperature and pressure, the actual Ginna sump water pH history ranging from 7.9 to 9.7 (See Section 3.4, "Containment Sump Water Chemistry" of this SE), and the auxiliary building ventilation system (ABVS) design. The Ginna ABVS consists of a single 100% capacity bank of HEPA filters, a single charcoal filter bank, and redundant 100% capacity fans discharging to the environment through the plant vent. On the receipt of a high radiation alarm, the auxiliary building air supply fans and all exhaust fans are tripped except those exhausting to the vent through the charcoal filters. The licensee did not take any credit for the removal of iodine through the ABVS filters because the loss of offsite power assumed in the LOCA analysis results in a loss of power to the ventilation fans.

In order to address the uncertainty in the amount of iodine that becomes airborne (5% to 2%) from the leaked ECCS fluid, in its review the staff considered (1) potential availability of the HEPA and charcoal filters provided in the ABVS during and following a LOCA, (2) actual sump water pH history, (3) the ABVS design for dilution and holdup of iodine that becomes airborne, (4) the licensee's constant enthalpy calculation which were based on Ginna specific sump water temperature and pressure, and (5) the staff's previous acceptance of the amount of iodine that becomes airborne as a design basis. The major parameters and assumptions used by the licensee are listed in Table 2.9.2-1.

3. LOCA Control Room Modeling

The licensee assumed a control room isolation delay of 60 seconds to account for damper positioning and instrumentation delays, with an additional 10 seconds for the Control Room Emergency Air Treatment System (CREATS) to be operational following a LOCA. Following isolation, there will be no outside air makeup and a filtered recirculation flow of a minimum of 5400 cubic feet per minute (cfm) (6000 cfm nominal, less 10%) is initiated. The licensee assumed an unfiltered inleakage rate of 300 cfm and recirculation filter efficiencies of 94%, 94%, and 99% for elemental, organic, and particulate iodine, respectively.

In the SE for Amendment No. 87, with regard to the changes in the TS ventilation filter testing program (VFTP), the staff noted that for the CREATS, an absorber efficiency of approximately 97% for elemental and organic forms of iodine could be assumed. In the dose analyses supporting the EPU request, the licensee revised the CREATS filter efficiency to 94% for elemental and organic forms of iodine, which is appropriately bounded by the licensee's testing in accordance with RG 1.52 guidance.

LOCA Conclusion

The licensee re-evaluated the radiological consequences resulting from the postulated LOCA using the AST and concluded that the radiological consequences at the exclusion area boundary (EAB), low-population zone (LPZ), and control room are within the dose criteria specified in 10 CFR 50.67. The results of the licensee's radiological consequence calculation are provided in

Table 2.9.2-8 and the major parameters and assumptions used by the licensee and found acceptable by the staff are listed in Table 2.9.2-1.

The radiological consequences of the LOCA at the EAB and at the LPZ calculated by the licensee are within the dose criteria specified in 10 CFR 50.67 and the control room dose is within the limit established by GDC 19. The staff performed independent calculations and confirmed the licensee's conclusions.

b. Fuel-Handling Accident (FHA)

The FHA assumes the dropping of a spent fuel assembly during refueling. This event could occur inside the containment or in the fuel storage building. The affected assembly is assumed to be that with the highest inventory of radionuclides of the fuel assemblies in the core. All of the fuel rods in the assembly are conservatively assumed to rupture. Volatile constituents of the core fission product inventory migrate from the fuel pellets to the gap between the pellets and the fuel rod clad. The radionuclide inventory in the fuel rod gap of the damaged fuel rods is assumed to be instantaneously released. Fission products released from the damaged fuel are decontaminated by passage through the overlaying water in the reactor cavity or spent fuel pool, to differing degrees depending on their physical and chemical form. Appendix B of RG 1.183 identifies acceptable radiological analysis assumptions for an FHA.

The licensee assumed no decontamination for noble gases, an effective decontamination factor of 200 for radioiodines, and retention of all aerosol and particulate radionuclides within the spent fuel pool water. The licensee assumed that 100% of the radionuclides released from the reactor cavity are released to the environment in two hours without any credit for filtration, holdup, or dilution. For an FHA in the spent fuel pool, the licensee assumed iodine removal by the auxiliary building ventilation system charcoal filters (90% for elemental iodine and 70% for organic iodine). All of the above assumptions are consistent with the guidance provided in RG 1.183. The Ginna TSs require operation of the auxiliary building ventilation system during irradiated fuel movement within the auxiliary building when one or more fuel assemblies in the auxiliary building have decayed less than 60 days since being irradiated. The charcoal filters are tested in accordance with the Ginna TS Section 5.5.10, "Ventilation Filter Testing Program."

A decay time of 100 hours prior to moving irradiated fuel was assumed for both the FHA in the containment and in the spent fuel pool. To ensure that the analysis would be bounding for both release cases, the licensee performed the analysis using the atmospheric dispersion factors for the most limiting combination of release point and receptor (See Section 2.9.2.3, "Atmospheric Dispersion Estimates," of this SE).

The licensee assumed a control room isolation delay of 60 seconds to account for damper positioning and instrumentation delays with an additional 10 seconds for the CREATS to be operational following an FHA. Following isolation, there will be no outside air makeup and a filtered recirculation flow of 5400 cfm (6000 cfm nominal, less 10%) is initiated. The licensee assumed an unfiltered inleakage rate of 300 cfm and recirculation filter efficiencies of 94%, 94%, and 99% for elemental, organic, and particulate iodine, respectively.

The staff found that the licensee used analysis assumptions and inputs consistent with applicable regulatory guidance identified in Section 2.9.2.1 of this SE and with those stated in the Ginna UFSAR as design bases. The assumptions found acceptable to the staff are presented in Table

2.9.2-2. The EAB, LPZ, and control room doses estimated by the licensee for the FHA were found to meet the applicable accident dose acceptance criteria in SRP 15.0.1 and are therefore acceptable. The results of the licensee's FHA radiological consequence calculation are provided in Table 2.9.2-8. The staff determined that no independent calculations were needed to confirm the licensee's conclusions for this particular DBA, based on similar results from Amendment No. 87 (issued February 25, 2005) to the Ginna license, which implemented an alternative source term in accordance with 10 CFR 50.67. The licensee has adequately accounted for the effects of the proposed EPU on this analyses, which show an increase of 16.8% reactor power, and the results remain well below the dose acceptance criteria.

c. MSLB

The MSLB accident considered is the complete severance of the 36-inch main steam header outside containment inside the turbine building. This is the largest MSLB outside containment. The radiological consequences of a break outside containment will bound the consequences of a break inside containment. Thus, only the MSLB outside of containment is considered with regard to the radiological consequences. The single failure is assumed to be a failure of the main steam isolation valve on the faulted SG. The faulted SG will rapidly depressurize and release the initial contents of the SG to the environment. A reactor trip occurs, main steam isolation occurs, safety injection actuates, and a loss of offsite power (LOOP) is assumed to occur concurrently with the reactor trip. Because the LOOP renders the main condenser unavailable, the plant is cooled down by releases of steam to the environment through the SG atmospheric relief valves (ARVs). The MSLB accident is described in the Ginna UFSAR Section 15.1.5, "Spectrum of Steam System Piping Failure Inside and Outside of Containment." Appendix E of RG 1.183 identifies acceptable radiological analysis assumptions for an MSLB.

The licensee stated that no fuel damage is postulated to occur because of an MSLB. Two radioiodine spiking cases are considered. The first assumes that a pre-incident radioiodine spike occurred just before the event and the RCS radioiodine inventory is at the maximum value for 100% power permitted by TSs. The second case assumes the event initiates a co-incident radioiodine spike. Radioiodine is released from the fuel to the RCS at a rate 500 times the normal radioiodine appearance rate for 8 hours. At approximately 10 minutes, the faulted SG is isolated by operator action. The intact SG is then used for cooldown, where steam is released to the atmosphere through the intact SG atmospheric relief valve. The licensee assumed that the faulted SG boils and becomes dry at 10 minutes, releasing the entire liquid inventory and entrained radionuclides through the faulted steam line to the environment.

Leakage from the RCS to the SGs is assumed to be the maximum value permitted by TSs. Primary-to-secondary leakage is assumed to be 1 gpm each to the faulted and intact SGs. The leakage to the faulted SG is assumed to immediately flash to steam and be released to the environment without holdup or dilution. The leakage in the unaffected SG mixes with the bulk water and is released at the assumed steaming rate for 8 hours. The licensee determined that the tubes in the unaffected SG would remain covered by the bulk water. The licensee assumed that the radionuclide concentration in the SG is partitioned such that 1% of the radionuclides in the bulk water of the unaffected SG enters the vapor space and is released to the environment. No partitioning is assumed in the faulted SG.

The licensee assumed a control room isolation delay of 60 seconds to account for damper positioning and instrumentation delays with an additional 10 seconds for the CREATS to be operational following a MSLB accident. Following isolation, there will be no outside air makeup and a filtered recirculation flow of 5400 cfm (6000 cfm nominal, less 10%) is initiated. The licensee assumed an unfiltered inleakage rate of 300 cfm and recirculation filter efficiencies of 94%, 94%, and 99% for elemental, organic, and particulate iodine, respectively.

The staff found that the licensee used analysis assumptions and inputs consistent with applicable regulatory guidance identified in Section 2.9.2.1 of this SE and with those stated in the Ginna UFSAR as design bases. The assumptions found acceptable to the staff are presented in Table 2.9.2-3. The results of the licensee's MSLB radiological consequence calculation are provided in Table 2.9.2-8. The EAB, LPZ, and CR doses estimated by the licensee for the MSLB were found to meet the applicable accident dose acceptance criteria in SRP 15.0.1 and are therefore acceptable. The staff determined that no independent calculations were needed to confirm the licensee's conclusions for this particular DBA, based on similar results from Amendment No. 87 (issued February 25, 2005) to the Ginna license, which implemented an alternative source term in accordance with 10 CFR 50.67. The licensee has adequately accounted for the effects of the proposed EPU on this analyses, which show an increase of 16.8% reactor power, and the results remain well below the dose acceptance criteria.

d. SGTR

The accident considered is the complete severance of a single tube in one of the SGs resulting in the transfer of RCS water to the ruptured SG. The primary-to-secondary break flow through the ruptured tube following a SGTR results in radioactive contamination of the secondary system. A reactor trip occurs, safety injection actuates, and a LOOP is assumed to occur concurrently with the reactor trip. Because the LOOP renders the main condenser unavailable, the plant is cooled down by release of steam to the environment through the ARVs. The licensee determined that the most limiting single failure is a single ARV on the intact SG failing open, providing a continuous release path to the environment. The failed ARV is assumed to be closed by manual operator action within 25 minutes. Appendix F of RG 1.183 identifies acceptable radiological analysis assumptions for an SGTR.

Two radioiodine spiking cases are considered. The first assumes that a pre-incident radioiodine spike occurred just before the event and the RCS radioiodine inventory is at the maximum value for 100% power permitted by TSs. The second case assumes the event initiates a co-incident radioiodine spike. Radioiodine is released from the fuel to the RCS at a rate 335 times the normal radioiodine appearance rate for 8 hours. The licensee assumed that a portion of the break flow flashes to vapor, rises through the bulk water, enters the steam space, and is immediately released to the environment with no mitigation or holdup. The flashing fraction ranges from 0 to 0.17, averaging a value of approximately 0.04. The portion of the break flow that does not flash is assumed to mix with the bulk water of the SG. In addition to the break flow, the licensee assumed there is primary-to-secondary leakage at the maximum value permitted by TSs. Primary-to-secondary leakage is assumed to be 150 gallons per day (gpd) into the bulk water of the unaffected SG.

The radionuclides in the bulk water are assumed to become vapor at a rate that is a function of the steaming rate for the SGs and the partition coefficient. The licensee determined that tubes in the unaffected SG would remain covered by the bulk water. The licensee assumed that the radionuclide concentration in the SG is partitioned such that 1% of the radionuclides in the unaffected SG bulk water enter the vapor space and are released to the environment. The partition coefficient does not apply to the flashed break flow. The steam release from the ruptured and unaffected SGs continues until the RHR system can be used to complete the cooldown at approximately 8 hours.

The licensee assumed a control room isolation delay of 360 seconds to account for damper positioning and instrumentation delays with an additional 10 seconds for the CREATS to be operational following an SGTR accident. Following isolation, there will be no outside air makeup and a filtered recirculation flow of 5400 cfm (6000 cfm nominal, less 10%) is initiated. The licensee assumed an unfiltered inleakage rate of 300 cfm and recirculation filter efficiencies of 94%, 94%, and 99% for elemental, organic, and particulate iodine, respectively.

The staff found that the licensee used analysis assumptions and inputs consistent with applicable regulatory guidance identified in Section 2.9.2.1 of this SE and with those stated in the Ginna UFSAR as design bases. The assumptions found acceptable to the staff are presented in Table 2.9.2-4. The results of the licensee's SGTR radiological consequence calculation are provided in Table 2.9.2-8. The EAB, LPZ, and control room doses estimated by the licensee for the SGTR were found to meet the applicable accident dose acceptance criteria in SRP 15.0.1 and are therefore acceptable. The staff determined that no independent calculations were needed to confirm the licensee's conclusions for this particular DBA, based on similar results from Amendment No. 87 (issued February 25, 2005) to the Ginna license, which implemented an alternative source term in accordance with 10 CFR 50.67. The licensee has adequately accounted for the effects of the proposed EPU on this analyses, which show an increase of 16.8% reactor power, and the results remain well below the dose acceptance criteria.

e. RCP Locked Rotor Accident (LRA)

The accident considered is the instantaneous seizure of a reactor coolant pump rotor (i.e., a locked rotor accident) which causes a rapid reduction in the flow through the affected RCS loop. A reactor trip occurs, safety injection actuates, and a LOOP is assumed to occur concurrently with the reactor trip. The flow imbalance creates localized temperature and pressure changes in the core. If severe enough, these differences may lead to localized boiling and fuel damage. Because the LOOP renders the main condenser unavailable, the plant is cooled down by releases of steam to the environment through the ARVs. Appendix G of RG 1.183 identifies acceptable radiological analysis assumptions for an LRA.

The licensee conservatively assumed that 50% of the fuel rods will experience departure from nucleate boiling (DNB) and are therefore, assumed to release their gap activity into the RCS. A radial peaking factor of 1 was applied considering the large portion of the core fuel assumed damaged. The radionuclides released from the fuel are assumed to be instantaneously and homogeneously mixed in the RCS and transported to the secondary side via primary-to-secondary leakage of 500 gpd for each SG for eight hours. The licensee assumed that this leakage mixes with the bulk water of the SGs and that the radionuclides in the bulk water become vapor at a rate that is a function of the steaming rate for the SGs and the partition coefficient. The tubes in the SGs would remain covered by the bulk water. The licensee assumed an iodine partition of 100 for elemental iodine release and a partition of 1.0 for organic iodide release. The steam releases from the SGs continue until the RHR system can be used to complete the cooldown at approximately 8 hours.

The licensee assumed a control room isolation delay of 60 seconds to account for damper positioning and instrumentation delays with an additional 10 seconds for the CREATS to be operational following a LRA. Following isolation, there will be no outside air makeup and a filtered recirculation flow of 5400 cfm (6000 cfm nominal, less 10%) is initiated. The licensee assumed an unfiltered inleakage rate of 300 cfm and recirculation filter efficiencies of 94%, 94%, and 99% for elemental, organic, and particulate iodine, respectively.

The staff found that the licensee used analysis assumptions and inputs consistent with applicable regulatory guidance identified in Section 2.9.2.1 of this SE and with those stated in the Ginna UFSAR as design bases. The assumptions found acceptable to the staff are presented in Table 2.9.2-5. The results of the licensee's LRA radiological consequence calculation are provided in Table 2.9.2-8. The EAB, LPZ, and control room doses estimated by the licensee for the LRA were found to meet the applicable accident dose acceptance criteria in SRP 15.0.1 and are therefore acceptable. The staff determined that no independent calculations were needed to confirm the licensee's conclusions for this particular DBA, based on similar results from Amendment No. 87 (issued February 25, 2005) to the Ginna license, which implemented an alternative source term in accordance with 10 CFR 50.67. The licensee has adequately accounted for the effects of the proposed EPU on this analyses, which show an increase of 16.8% reactor power, and the results remain well below the dose acceptance criteria.

f. Rod Ejection Accident (REA)

The accident considered is the mechanical failure of a control rod drive mechanism pressure housing that results in the ejection of a rod cluster control assembly and drive shaft. Localized damage to fuel cladding and a limited amount of fuel melt are projected due to the reactivity spike. This failure breaches the reactor pressure vessel head resulting in a release of coolant to the containment. A reactor trip occurs, safety injection actuates, and a LOOP is assumed to occur concurrently with the reactor trip. Because the LOOP renders the main condenser unavailable, the plant is cooled down by releases of steam to the environment through the ARVs. The release to the environment is assumed to occur through two separate pathways:

• Release of containment atmosphere by design leakage

• Release of RCS inventory via primary-to-secondary leakage through SGs.

While the actual doses from an REA would be a composite of the two pathways, an acceptable dose from each pathway, modeled as if were the only pathway, would show that the composite dose would also be acceptable. Appendix H of RG 1.183 identifies acceptable radiological analysis assumptions for an REA.

The licensee assumed that 15% of the fuel rods fail releasing the radionuclide inventory in the fuel rod gap. The design basis REA in Section 15.4.5.3.5 of the Ginna UFSAR stated that less than 10% of the fuel rod enters DNB based on a detailed Ginna specific three-dimensional THINC analysis. The licensee further assumed that 10% of the core inventory of radioiodines and noble gases is in the fuel rod gap. A radial peaking factor of 1.75 was applied. In addition, localized heating is assumed to cause 0.25% of the fuel to melt. For the secondary release case, 100% of the noble gases and 50% of the radioiodines contained in the melted fuel are released to the secondary side of the SGs.

For the containment leakage case, the radionuclides released from the fuel are assumed to be instantaneously and homogeneously mixed in the containment free volume. The licensee assumed that the containment leaks at the TS value of 0.2% volume per day for the first 24 hours and 0.1% volume per day for days 2 through 30, consistent with the guideline provided in RG 1.183. The licensee has taken credit for removal of iodine in particulate form by the HEPA filters in the containment recirculation and filtration system (CRFS) but not iodine in elemental and organic forms. The CRFS is a safety related system and its operational requirements are specified in the Ginna TSs.

The licensee does not credit CS operation as a radionuclide removal mechanism. However, the licensee does assume that natural deposition processes result in a removal of aerosols at a rate of 0.023 hr^{-1} based on the methodology of NUREG/CR-6189, "A Simplified Model of Aerosol Removal by Natural Processes in Reactor Containments." The staff finds the use of this methodology acceptable as discussed in RG 1.183.

For the secondary release case, the radionuclides released from the fuel are assumed to be instantaneously and homogeneously mixed in the RCS and transported to the secondary side via primary-to-secondary leakage at 500 gpd for each SG for eight hours, which bounds the current TS value of 144 gpd. The licensee assumed that this leakage mixes with the bulk water of the SGs and that the radionuclides in the bulk water become vapor at a rate that is a function of the steaming rate for the SGs and the partition coefficient. The licensee assumed that the chemical form of the radioiodine released to the environment would be 97% elemental and 3% organic consistent with the guideline provided in RG 1.183. The licensee assumed that the aerosol and iodine radionuclides that enter the unaffected SGs from the RCS enter the vapor space and are released to the environment. This assumption is also consistent with the guideline provided in RG 1.183. The steam releases from the SGs continue until the RHR system can be used to complete the cooldown at approximately 8 hours.

The licensee assumed a control room isolation delay of 60 seconds to account for damper positioning and instrumentation delays with an additional 10 seconds for the CREATS to be operational following an REA. Following isolation, there will be no outside air makeup and a filtered recirculation flow of 5400 cfm (6000 cfm nominal, less 10%) is initiated. The licensee assumed an unfiltered inleakage rate of 300 cfm and recirculation filter efficiencies of 94%, 94%, and 99% for elemental, organic, and particulate iodine, respectively.

The staff found that the licensee used analysis assumptions and inputs consistent with applicable regulatory guidance identified in Section 2.9.2.1 of this SE and with those stated in the Ginna UFSAR as design bases. The assumptions found acceptable to the staff are presented in Table 2.9.2-6. The results of the licensee's REA radiological consequence calculation are provided in Table 2.9.2-8. The EAB, LPZ, and control room doses estimated by the licensee for both cases of the REA were found to meet the applicable accident dose acceptance criteria in SRP 15.0.1 and are therefore acceptable. The staff determined that no independent calculations were needed to confirm the licensee's conclusions for this particular DBA, based on similar results from Amendment No. 87 (issued February 25, 2005) to the Ginna license, which implemented an alternative source term in accordance with 10 CFR 50.67. The licensee has adequately accounted for the effects of the proposed EPU on this analyses, which show an increase of 16.8% reactor power, and the results remain well below the dose acceptance criteria.

g. Tornado Missile Accident (TMA)

The staff does not consider this event as a DBA and it is neither listed nor addressed in RG 1.183 or in SRP 15.0.1. Nevertheless, the licensee did a radiological evaluation of this event because it was previously analyzed in Section 9.1, “Fuel Storage and Handling,” of the Ginna UFSAR and is a part of the Ginna licensing and design basis.

The licensee analyzed this event to determine the radiological consequence resulting from damage to stored spent fuel from the impact of a tornado missile. The licensee assumed that the hypothetical tornado missile propelled by the wind penetrates the auxiliary building roof and impacts 9 fuel assemblies in the spent fuel storage pool (5 fuel assemblies decayed for 100 hours and 4 fuel assemblies decayed for 60 days). In its analysis, the licensee further assumed the tornado missile to be a 1490-pound wooden pole, 35 feet in length and 13.5 inch in diameter. These assumptions are design bases in the Ginna UFSAR Section 9.1 which the staff has previously accepted in its evaluation. All other assumptions and parameters used in the radiological consequence analysis of this event are the same as those used in the FHA above. Neither control room isolation nor re-circulating filtration is assumed.

The staff found that the licensee used analysis assumptions and inputs consistent with applicable regulatory guidance identified in Section 2.9.2.1 of this SE. The assumptions found acceptable to the staff are presented in Table 2.9.2-7. The results of the licensee’s TMA radiological consequence calculation are provided in Table 2.9.2-8. In lieu of accident specific criteria, the staff considered the dose acceptance criteria for the FHA, which is a reasonably similar accident with respect to the source term. The EAB, LPZ, and control room doses estimated by the licensee for this event were found to meet the FHA dose acceptance criteria and are therefore acceptable. The staff determined that no independent calculations were needed to confirm the licensee’s conclusions for this particular DBA, based on similar results from Amendment No. 87 (issued February 25, 2005) to the Ginna license, which implemented an alternative source term in accordance with 10 CFR 50.67. The licensee has adequately accounted for the effects of the proposed EPU on this analyses, which show an increase of 16.8% reactor power, and the results remain well below the dose acceptance criteria.

2.9.2.3 Atmospheric Dispersion Estimates

The licensee used existing atmospheric dispersion factors (χ/Q values) to perform dose assessments related to potential accidental releases from the Ginna nuclear power plant to evaluate the impact of the extended power uprate on the Ginna control room, EAB and LPZ. These χ/Q values were previously generated by the licensee in support of Ginna License Amendment No. 87, dated February 25, 2005 (ADAMS accession number ML050320491).

As stated in the SE associated with Amendment No. 87, the licensee calculated control room, EAB and LPZ χ/Q values to evaluate containment leakage, containment equipment hatch (roll-up door), atmospheric relief valve, plant vent, auxiliary building leakage, MSLB, and spent fuel pool releases. All postulated releases were considered ground level releases. Other than the first minute of the spent fuel releases due to the tornado missile accident, the licensee calculated control room air intake χ/Q values using the ARCON96 computer code (NUREG/CR-6331, Revision 1, “Atmospheric Relative Concentrations in Building Wakes”) and EAB and LPZ χ/Q values using the PAVAN computer code (NUREG/CR-2858, "PAVAN: An Atmospheric Dispersion Program for Evaluating Design Bases Accident Releases of Radioactive Material from Nuclear Power Stations"). Hourly data from the 33-foot (10-meter) and 150-foot (45.7-meter) levels on the onsite meteorological tower were provided as input to ARCON96 whereas the joint frequency distribution used as input to PAVAN was compiled using wind data from the 10-meter level. Stability class was based on delta-temperature measurements made between the 45.7-meter and 10-meter levels on the onsite meteorological tower.

Spent fuel pool releases due to a tornado missile accident assumed that the resulting radiological releases were dispersed during the first minute of the accident by the “tornado conditions” that caused the accident. For generation of the control room χ/Q values, these tornado conditions were represented by the highest 10-m wind speed recorded onsite during the period 1999–2003 (stability D with a 22.1 m/s wind speed). When generating EAB and LPZ χ/Q values, The licensee modeled the first minute of the spent fuel pool tornado missile accident using the CONHAB module of the HABIT computer code (NUREG/CR-6210, Supp. 1, “Computer Codes for Evaluation of Control Room Habitability [HABIT V1.1]”) and assumed F stability and 22.1 m/s atmospheric conditions. For subsequent time periods, dispersion factors were determined using the typical ARCON96 and PAVAN model results.

The licensee did not generate new χ/Q values for this amendment request. Because the accident release points and receptors are not changed for the EPU, the χ/Qs remain unchanged. Based on the review described in the SE associated with Ginna Amendment No. 87, the NRC staff has concluded that the Ginna χ/Q values previously generated by the licensee in support of Ginna License Amendment No. 87 are acceptable for use in the design basis accident control room, EAB and LPZ dose assessments performed in support of this extended power uprate license amendment request. These values are presented in Tables 2.9.2-9 and 2.9.2-10.

2.9.2.4 Radiological Consequences Analyses Conclusion

The NRC staff has evaluated the licensee’s revised accident analyses performed in support of the proposed EPU and concludes that the licensee has adequately accounted for the effects of the proposed EPU. The NRC staff further concludes that the plant site and the dose-mitigating engineered safety features (ESFs) remain acceptable with respect to the radiological consequences of postulated DBAs since, as set forth above, the calculated total effective dose equivalent (TEDE) at the EAB, at the (LPZ) outer boundary, and in the control room meet the exposure guideline values specified in 10 CFR 50.67 and GDC 19, as well as applicable acceptance criteria denoted in SRP 15.0.1. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to the radiological consequences of DBAs.

Table 2.9.2-1
LOCA Radiological Consequences Analysis Assumptions

Parameter	Value
Reactor power	1811 MWt
Containment volume	1.0E+6 ft^3
Sprayed area	7.8E+5 ft^3
Unsprayed area	2.2E+5 ft^3
Containment leak rates	
0 to 24 hours	0.2% per day
24 to 720 hours	0.1% per day
Containment mixing rates	
Sprayed to unsprayed	4.5E+4 ft^3/hr
Unsprayed to sprayed	4.5E+4 ft^3/hr
Aerosol removal rates by containment spray (per hour)	
Time	Rates
0 to 80 seconds	0
80 seconds to 52 minutes	3.5
52 minutes to 3 days	0
Elemental iodine removal rates by spray (per hour)	
Time	Rates
0 to 80 seconds	0
80 seconds to 52 minutes	20
52 minutes to 30 days	0
Containment sump volume	2.647E+5 gal
ECCS leak rates	
Time	Rates
0 to 60 minutes	0
60 minutes to 30 days	4.0 gph
Iodine partition factors	2 to 5%
Release points	
Containment leakage	Containment
ECCS leakage	Auxiliary building

Table 2.9.2-2
FHA Radiological Consequences Analysis Assumptions

Parameter	Value
Reactor power	1811 MWt
Radial peaking factor	1.75
Fission product decay period	100 hours
Number of fuel assembly damaged	1
Fuel pool water depth	23 ft
Fuel gap fission product inventory (%)	
Noble gases excluding Kr-85	5
Kr-85	10
I-131	8
Other halogens	5
Alkali metals	12
Fuel pool decontamination factors	
Iodine	200
Noble gases	1
Fission product inventory and activity released	Submittal Table 6.3
Duration of accident	2 hours
Release filtration or holdup	None credited
Release points	
FHA inside containment	Containment equipment hatch
FHA in spent fuel pool	Plant vent

Table 2.9.2-3
MSLB Radiological Consequences Analysis Assumptions

Parameter	Value
Pre-incident iodine spike activity	60 μCi/gm dose equivalent I-131
Co-incident spike appearance rate	1 μCi/gm dose equivalent I-131
Co-incident spike multiplier	500
Iodine spike duration, hrs	8
Chemical form release fractions	
Elemental	0.97
Organic	0.03
Primary-to-secondary leakage per SG, gpm	1
Duration, hours	8
Liquid Masses, gm	
RCS	1.28E+8
SG (each)	5.65E+7
Steam release from faulted SG	
0 to 610 seconds	5.12E+7 gm
610 seconds to 8 hours	1 gal/min
Steam release from intact SG, gm/min	
0 to 2 hours	8.23E+5
2 to 8 hours	5.65E+5
Steam iodine partition coefficient in SGs	
Faulted SG (elemental and organic)	1.0
Unaffected SG	
Elemental	0.01
Organic	1.0
Release point	Turbine building main steam header

Table 2.9.2-4
SGTR Radiological Consequences Analysis Assumptions

Parameter	Value
Pre-incident iodine spike activity	60 μCi/gm dose equivalent I-131
Co-incident spike appearance rate	1 μCi/gm dose equivalent I-131
Co-incident spike multiplier	335
Iodine spike duration, hrs	8
Chemical form release fractions	
Elemental	0.97
Organic	0.03
Primary-to-secondary leakage to intact SG, gpd	150
Duration, hours	8
Liquid Masses, gm	
RCS	1.28E+8
SG (each)	3.86E+7
Steam release from faulted SG, lbm	
0 to 174 seconds	189,100
174 to 5234 seconds	76,000
Steam generator rupture flow, lbm	
0 to 174 seconds	4,200
174 to 2596 seconds	86,839
2596 to 5234 seconds	62,961
Steam release from intact SG, lbm	
0 to 174 seconds	188,400
174 to 5234 seconds	104,700
5234 seconds 2 hours	88,800
2 to 8 hours	513,100
8 to 40 hours	1,760,100
Steam generator iodine partition coefficients	
elemental and organic	1.0
Release point	Atmospheric relief valves

Table 2.9.2-5
LRA Radiological Consequences Analysis Assumptions

Parameter	Value	
Radial peaking factor	1.0	
Fraction of failed fuel	0.50	
Fraction of Core Inventory in Gap		
Kr-85	0.10	
I-131	0.08	
Alkali metals	0.12	
Other noble gases / iodines	0.05	
Iodine speciation	Containment	Secondary
Aerosol	0.95	0
Elemental	0.0485	0.97
Organic	0.0015	0.3
Primary to secondary leakage per SG, gpd	500	
Primary to secondary leakage duration, hours	8	
Steam generator mass in 2 SGs, gm	7.72E+7	
Steam partition coefficient in SGs	0.01	
Steam release from 2 SGs, lbm		
0 to 2 hours	210,300	
2 to 8 hours	484,500	
Release point	Atmospheric relief valves	

Table 2.9.2-6
REA Radiological Consequences Analysis Assumptions

Parameter	Value	
Radial peaking factor	1.75	
Fraction of rods that exceed DNB	0.15	
Gap fraction, all nuclide groups	0.10	
Fraction of rods in core that exceed DNB	0.00375	
Iodine species fraction	CNMT	SG
Particulate/aerosol	0.95	0
Elemental	0.0485	0.97
Organic	0.0015	0.03
Containment free volume, ft^3	1.0E+6	
Containment Sprays	Not credited	
Containment release		
0-24 hours, %/day	0.2	
24-720 hours, %/day	0.1	
Containment Particulate deposition 1/hr	0.023	
Duration of release, days	30	
Containment fan cooler iodine removal efficiencies		
Aerosols	95	
Elemental/organic	0	
Primary to secondary leakage per SG, gpd	500	
Primary to secondary leakage duration, hours	8	
Steam generator mass for 2 SGs, lbm	7.72E+7	
Steam partition coefficient in SGs	0.01	
Steam release from 2 SGs, lbm		
0 to 2 hours	210,300	
2 to 8 hours	484,500	
Release points		
Containment leakage	Containment	
Secondary	Atmospheric relief valves	

Table 2.9.2-7
TMA Radiological Consequences Analysis Assumptions

Parameter	Value
Number of damaged fuel assemblies	
Hot	5
Cold	4
Decay times	
Hot	100 hours
Cold	60 days
Fraction of Core Inventory in Gap	
Kr-85	0.10
I-131	0.08
Alkali metals	0.12
Other noble gases / iodines	0.05
Iodine species above water	
Elemental	0.57
Organic	0.43
Overall pool DF	200
Iodine removal filter efficiencies for all forms	0

Table 2.9.2-8
Ginna DBA Radiological Consequences, TEDE (rem)

Design Basis Accidents	EAB [2]	LPZ [3]	Control Room
LOCA	3.1	1.2	4.6
Dose criteria [1]	25	25	5.0
Fuel handing accident in containment	6.1E-1	7E-2	1.4
Dose criteria	6.3	6.3	5.0
Fuel handing accident in auxiliary building	1.7E-1	2E-2	1.2E-1
Dose criteria	6.3	6.3	5.0
Main steamline break accident [4]	4.5E-1	1.2E-1	5.8E-1
Dose criteria	2.5	2.5	5.0
Main steamline break accident [5]	7E-2	3E-2	1.7E-1
Dose criteria	25	25	5.0
Steam generator tube rupture [4]	1.7E-1	3E-2	2.2E-1
Dose criteria	2.5	2.5	5.0
Steam generator tube rupture [5]	4.4E-1	6E-2	9.4E-1
Dose criteria	25	25	5.0
Locked rotor accident	1.16	3.5E-1	1.87
Dose criteria	2.5	2.5	5.0
Rod ejection accident	1.34	4.1E-1	1.83
Dose criteria	6.3	6.3	5.0
Tornado missile accident	3E-2	1E-2	6.3E-1 [6]
Dose criteria	6.3	6.3	5.0

[1] Total effective dose equivalent
[2] Exclusion area boundary
[3] Low population zone
[4] Accident initiated iodine spike
[5] Pre-accident iodine spike
[6] Maximum dose without CR recirculation filtration

Table 2.9.2-9
Ginna Control Room χ/Q Values (sec/m^3)

Release Point	0-2 hr	2-8 hr	8-24 hr	24-96 hr	96-720 hr
Main Steam Header	2.59×10^{-3}	1.88×10^{-3}	8.28×10^{-4}	5.90×10^{-4}	4.47×10^{-4}
Intact SG ARV	3.72×10^{-3}	2.51×10^{-3}	1.15×10^{-3}	8.35×10^{-4}	6.88×10^{-4}
Containment Shell	1.77×10^{-3}	1.25×10^{-3}	4.80×10^{-4}	4.24×10^{-4}	3.66×10^{-4}
Auxiliary Building	4.69×10^{-3}	3.97×10^{-3}	1.40×10^{-3}	1.32×10^{-3}	1.11×10^{-3}
Containment Equipment Hatch Roll-up Door	5.58×10^{-3}	4.66×10^{-3}	1.65×10^{-3}	1.58×10^{-3}	1.32×10^{-3}
Plant Vent	1.99×10^{-3}	1.46×10^{-3}	6.35×10^{-4}	5.01×10^{-4}	4.47×10^{-4}
Spent Fuel Pool	5.14×10^{-5}* 1.44×10^{-3}**	1.22×10^{-3}	4.54×10^{-4}	4.17×10^{-4}	3.38×10^{-4}

* 0 to 1 minute (tornado conditions)
** 1 minute to 2 hours

Table 2.9.2-10
Ginna Offsite χ/Q Values (sec/m^3)

Accidents Other Than Tornado Missile Accident

Boundary	2 hr^	0-8 hr	8-24 hr	24-96 hr	96-720 hr
EAB	2.17×10^{-4}	---	---	---	---
LPZ	---	2.51×10^{-5}	1.78×10^{-5}	8.50×10^{-6}	2.93×10^{-6}

Tornado Accident Missile Accident Only

Boundary	0-1 min	1 min-2 hr^	1 min-8 hr	8-24 hr	24-96 hr	96-720 hr
EAB	2.17×10^{-6}	2.17×10^{-4}	---	---	---	---
LPZ	4.17×10^{-7}	---	2.51×10^{-5}	1.78×10^{-5}	8.50×10^{-6}	2.93×10^{-6}

^ Any two hour period

2.10 Health Physics

2.10.1 Occupational and Public Radiation Doses

Regulatory Evaluation

The NRC staff conducted its review in this area to ascertain what overall effects the proposed EPU will have on both occupational and public radiation doses and to determine that the licensee has taken the necessary steps to ensure that any dose increases will be maintained within applicable regulatory limits and as low as is reasonably achievable (ALARA). The NRC staff's review included an evaluation of any increases in radiation sources and how this may affect plant area dose rates, plant radiation zones, and plant area accessibility. The NRC staff evaluated how personnel doses needed to access plant vital areas following an accident are affected. The NRC staff also considered the effects of the proposed EPU on plant effluent levels and any effect this increase may have on radiation doses at the site boundary. The NRC's acceptance criteria for occupational and public radiation doses are based on 10 CFR Part 20, and 10 CFR Part 50, Appendix I. Specific review criteria are contained in SRP Sections 12.2, 12.3, 12.4, and 12.5, NUREG-0737, Item II.B.2, and other guidance provided in Matrix 10 of RS-001.

Technical Evaluation

Radiation Sources

The original plant shielding design for Ginna was based on a core power level of 1520 MWt and a 1-year fuel cycle length. The licensee is proposing a 16.8% EPU and an additional 2% measurement uncertainty recapture uprate (that will be requested at a later date). As a result of these two uprates, the new core power level will be 1811 MWt and the plant will operate on an 18-month fuel cycle. This represents an approximate 19% increase in power level. Although the current application is only for a 16.8% EPU, the licensee's analysis in the health physics area evaluated the effects of an approximate 19% EPU on both occupational and public radiation doses. (For clarification purposes, all future references to the proposed EPU in this section of the SE will assume an approximate 19% increase in core power, as assumed in the licensee's analysis). In general, the production of radiation and radioactive material (either fission or activation products) in the reactor core is directly dependent on the neutron flux and power level of the reactor. Therefore, an approximate 19% increase in power level is expected to result in a proportional increase in the direct (i.e. from the reactor fuel) and indirect (i.e., from the reactor coolant) radiation source terms.

The proposed EPU will require an increase in the nuclear fission rate which will lead to an increase in the nuclear flux in the reactor core. The increased flux will cause an increase in neutron activation products in the reactor cooling system, control rod assemblies, reactor internals, and the pressure vessel as well as an increase in the fission product inventory in the core and spent fuel. The increased flux will also result in an increase in neutron and gamma flux leakage out of the RV. The increased inventory of fission products in the core will increase the activity concentration in the reactor coolant due to fuel defects. The activity concentration in the secondary system will also increase due to primary to secondary leakage in the SGs. In addition, the increase of fuel cycle length will increase the inventory of long-lived isotopes in the core and in the reactor coolant. The increase in radioactivity levels and the associated increase in radiation source strength will result in an increase in radiation levels in the containment building, auxiliary building, intermediate building, turbine building, all-volatile-treatment building, and other buildings subject to direct shine from radiation sources contained in these buildings.

Radiation Levels

As stated earlier, the approximate 19% increase in power level associated with the proposed EPU is expected to result in a proportional increase in the direct and indirect radiation source terms. The licensee has utilized scaling techniques to determine the impact of the EPU on plant radiation levels in the major plant areas affected by this proposed power increase. The licensee's evaluation takes credit for conservatism in existing shielding analyses and the site ALARA program to demonstrate continued adequacy of current plant shielding to ensure compliance with the occupational dose limits of 10 CFR Part 20.

The radiation dose rates near the RV are determined by the neutron and gamma leakage flux from the RV during operation and by the gamma fluxes in the core and the activation activities in the RV internals, pressure vessel, and primary system piping walls during shutdown. The primary purpose of the reinforced concrete primary shield wall surrounding the RV is to attenuate the neutron and gamma fluxes leaking out of the RV. The licensee estimates that the normal operation radiation levels near the RV will increase by a factor of approximately 19% due to the increased neutron and gamma flux leakage resulting from the proposed EPU. However, in performing new design calculations to support the proposed EPU, the licensee has determined that the neutron and gamma fluxes from the RV are significantly less than those calculated in the original calculations. In addition, beginning in Cycle 11, the licensee has gradually changed to low leakage fuel management. This change to low leakage fuel management has resulted in lower neutron and gamma flux leakage from the reactor. The effect of low leakage fuel management at Ginna offsets the expected flux leakage increase due to the approximately 19% increase in the core power for the proposed EPU. The licensee stated that, with the continued use of low leakage fuel management following EPU, the existing primary shielding remains adequate and the estimated dose rates adjacent to the RV/primary wall will remain within original design levels following EPU. Therefore, the proposed EPU will not affect radiation zoning in this area.

The radiation dose rates in containment areas adjacent to the RCS during operation are determined primarily by the N-16 levels in the reactor coolant. The shutdown dose rates in these areas are determined primarily by the deposited corrosion product activity and the cobalt impurities in the RCS and the SG components. The licensee estimates that, following EPU, both the N-16 and corrosion product source terms will increase by approximately 19%, resulting in operating and shutdown radiation levels in these areas increasing by the same percentage. The primary function of the secondary shielding which surrounds the RCS and the SGs is to attenuate the radiation levels from the N-16 source to those areas of containment outside of this secondary shield. The licensee stated that the radiation levels resulting from the postulated increase in source terms following EPU will be bounded by the conservative analytical techniques used to establish plant shielding design and, therefore, the proposed EPU will not affect radiation zoning in these areas. The secondary shield was also designed to limit the full power dose rate outside the containment to less than 1 mrem/hr. Current survey data taken outside containment indicates that the dose rate contribution due to containment shine at full power operation adjacent to the containment wall is less than 0.1 mrem/hr. Following the proposed EPU, the licensee estimates that this dose rate adjacent to the containment wall will increase to less than 0.2 mrem/hr, which is still well within the secondary shield design basis of limiting the full power dose rate outside the containment building due to containment shine to less than 1 mrem/hr.

The radiation dose rates in areas near irradiated fuels (refueling canal, spent fuel pool, incore instrumentation drive assembly area) and other irradiated areas are determined primarily by the gamma rays from fission and activation products. The licensee estimates that, following EPU, both the fission products and the activation products will increase by approximately 19%. Ginna's Technical Requirements Manual states that Ginna can only offload fuel from the core into Region 1 of the spent fuel pool. The walls on two sides of Region 1 of the spent fuel pool are sufficiently thick to ensure that any increases in dose rates in accessible areas near this portion of the spent fuel pool will be negligible. Ginna has implemented procedural guidance to ensure that fuel assemblies with a power sharing value greater that 0.5 will not be put into locations immediately adjacent to the spent fuel pool walls in Region 1 of the spent fuel pool for 1 year following irradiation, thus reserving the fuel assembly locations adjacent to the wall for older decayed fuel or water cells. This practice will ensure that the gamma dose rates within the wall will be attenuated by a factor greater than the expected increase in gamma dose rates due to the proposed EPU. There are no accessible locations below the Ginna spent fuel pool. On the basis of these procedures and design features, the proposed EPU should have a negligible effect on dose rates in accessible areas adjacent to the sides of the spent fuel pool and will not affect the radiation zoning in these areas.

The fourth area considered were areas outside containment where the radiation source is derived from the primary coolant. In most of these areas, the radiation sources are fission products and corrosion products in the primary coolant or down-stream sources originating from the primary coolant activity. The licensee estimates that, following EPU, both the fission products and the activated corrosion products will increase by approximately 19%, resulting in an approximate 19% increase in radiation levels in these areas. The radiation levels near the condensate polishing system may increase greater than the percentage of the EPU due to the increased steam flow rate and moisture carryover fraction associated with the EPU. Typical dose rates adjacent to the condensate polishers at Ginna are less than 0.1 mrem/hr. Using this value, the licensee estimates that the EPU could result in an increase in dose rates adjacent to the condensate polishers that ranges from the more likely 27% up to a worst-case value of 800%. Based on the current dose rate of less than 0.1 mrem/hr in this area, the projected post-EPU dose rates adjacent to the condensate polishers could range from 0.13 mrem/hr to a conservative maximum of 0.8 mrem/hr. On the basis of these estimated dose rates, no additional personnel access controls will be required in this area other than continued use of existing plant ALARA procedures. An analysis performed by the licensee concluded that the TSs will limit the reactor coolant source terms and associated dose rates to 81% of the original design basis values and the TSs will maintain the reactor coolant gas activity and associated dose rates at approximately the original design basis values. Therefore, the proposed EPU will not affect the radiation zoning in areas outside containment where the radiation source is derived from the primary coolant.

As described above, the normal operation radiation levels in most of the plant area are expected to increase by approximately 19%. The licensee has stated that this expected increase in radiation levels will not affect radiation zoning or shielding requirements because of the conservatism in the licensee's shielding analyses, the conservatism in the original "design basis" reactor coolant source terms used to establish the plant radiation zones, and the TS limits on reactor coolant concentrations. In order to document any effects that the proposed EPU will have on plant radiation levels, Radiation Protection personnel will monitor all radiation monitors in the affected areas of the containment, auxiliary building, and intermediate building during the initial power ascension following the proposed EPU. They will also perform radiation surveys of specific plant areas where dose rates would be most likely to change following the EPU. If the licensee detects any abnormal readings, they will perform full surveys of the RCA to document these changes in dose rates. During the first at power containment entry following the proposed EPU, the licensee will perform surveys inside containment which they will then compare with pre-EPU containment radiation surveys. The licensee will use these surveys to evaluate any changes in containment radiation dose rates resulting from the EPU. The licensee will also use selected containment area and airborne radiation monitor readings to provide early warning of any abnormal dose rates in containment. The licensee will use the data gathered from these surveys to assure that all radiation areas are properly designated, posted, and controlled, in a timely manner, as required by 10 CFR Part 20 and TSs.

As a result of the proposed EPU, the normal operation radiation levels in most of the plant area are expected to increase by approximately 19%. The exposure to plant personnel and to the offsite public is also expected to increase by the same percentage. Over the past 10 years, the annual collective dose at Ginna has generally been well below the national average for pressurized-water reactors. The licensee estimates that the annual collective dose at Ginna will increase by approximately 19% as a result of implementing the proposed EPU. Assuming that the annual collective dose at Ginna does increase by approximately 19% following EPU, the resulting annual collective dose at Ginna should still be at or below the national average for pressurized-water reactors. The licensee has stated that the ALARA process at Ginna will identify opportunities to mitigate this expected increase in the source term (and resulting increase in collective dose) after the uprate is accomplished.

Item II.B.2 of NUREG-0737 states that the occupational worker dose guidelines of GDC 19 (10 CFR Part 50, Appendix A) shall not be exceeded during the course of an accident. Compliance with Item II.B.2 ensures that operators can access and perform required duties and actions in designated vital areas. GDC 19 requires that adequate radiation protection be provided such that the dose to personnel shall not exceed 5 rem whole body, or its equivalent, to any part of the body for the duration of the accident. Ginna has been approved for use of alternate source terms for post-accident dose assessments associated with onsite locations that require continuous occupancy such as the control room. For other plant vital areas, the licensee used the initial plant vital area information developed in the 1979 Design Review Report and reevaluated this information using the proposed EPU power level of 1811 MWt, operation with an 18-month fuel cycle, updated fuel burnup modeling/libraries, and a 4% margin to address uncertainty in fuel management schemes following EPU. The licensee has identified all vital areas and has calculated the personnel occupancy times and mission doses to access and perform the needed post-accident functions for each of these areas. The proposed EPU will not have any effect on the calculated mission doses associated with any of these designated vital areas. In response to NRC staff inquiries, the licensee has also provided plant layout drawings showing the access routes to these vital areas. The results of the licensee's evaluation of plant vital areas shows that the mission dose for each of the identified vital areas is below the dose limit of 5 rem whole body contained in GDC 19.

On the basis of information contained in the licensee's submittal regarding post EPU radiation levels, Ginna will continue to meet its design basis in terms of radiation shielding, in accordance with the criteria in SRP Section 12.4 and NUREG-0737, Item II.B.2.

Public and Offsite Radiation Exposures

The TS limits for Ginna implement the guidelines of 10 CFR Part 50, Appendix I for the annual dose to an individual in an unrestricted area. At the original rated power, the radiation effluent doses were a small fraction of the doses allowed by TS limits. The licensee estimates that the radioactivity content of the liquid releases will increase by a maximum of 19% as a result of the EPU. The projected doses from liquid effluents following EPU will still be a small fraction of the Appendix I Design Objectives. For gaseous effluents, the licensee estimates that the noble gases and tritium releases will be bounded by a maximum 19% increase while the "particulate and iodine" category will by bounded by a maximum 29.1% increase (due to the large increase in moisture carryover due to the EPU). The projected doses from gaseous effluents following EPU will still be significantly below the 10 CFR Part 50, Appendix I Design Objectives.

Although there are no regulations on the amounts of solid radioactive waste generated, the direct shine from solid radioactive waste stored onsite could affect the offsite radiation dose. 40 CFR Part 190 limits the annual whole body dose to an actual member of the public from all pathways due to liquid and gaseous releases and from direct radiation due to contained radioactive sources within the facility to 25 mrem to the whole body. The licensee does not expect that the plant will generate any additional radioactive waste volumes that will need to be processed by the radioactive waste systems as a result of the EPU. The increase in the total long-lived activity contained in the waste following EPU is expected to be bounded by approximately 21%. The pre-EPU annual direct shine dose (primarily due to solid radioactive waste stored onsite) ranged from 7.9 to 10.1 mrem over the 5-year period from 1999 to 2003. The pre-EPU annual whole body dose from all pathways due to liquid releases and gaseous releases were 0.003 and 0.007 mrem, respectively. Assuming that the EPU would increase the direct shine dose and the annual dose contributions from liquid and gaseous releases by approximately 21%, the resulting maximum post EPU annual dose to an actual member of the public from these sources would be 12.2 mrem. This is well below the 40 CFR Part 190 annual whole body dose limit of 25 mrem to a member of the public. The licensee stated that the procedures and controls in the Offsite Dose Calculation Manual would monitor the direct shine component of the offsite dose and, through administrative and storage controls, the licensee would limit the offsite dose to ensure continued compliance with the 40 CFR Part 190 dose limits.

On the basis of information contained in the licensee's submittal regarding public and offsite radiation exposures, any increase in offsite doses due to EPU will be well within the TS dose limits and below the limits of 10 CFR Part 20, 40 CFR Part 190, and the Design Objectives of 10 CFR Part 50, Appendix I.

Ensuring that Occupational and Public Radiation Exposures are ALARA

The Radiation Protection Program at Ginna Station ensures that internal and external radiation exposures to station personnel, contractor personnel and the general population resulting from station operation will be within applicable limits and will be ALARA. Design features currently in place at Ginna Station to support Ginna's commitment to ALARA exposures include shielding to reduce levels of radiation, ventilation arranged to control the flow of potentially contaminated air, an installed radiation monitoring system used to measure levels of radiation in potentially occupied areas and measure airborne radioactivity throughout the plant, and respiratory protection equipment which is used as prescribed by the Radiation Protection Program. Compliance with the requirements of the Offsite Dose Calculation Manual ensures that radioactive discharges and public exposures are ALARA. The design features currently in place at Ginna Station will be able to compensate for the anticipated increases in dose rates associated with the EPU. Therefore, the increased radiation sources resulting from this proposed EPU will not adversely impact the licensee's ability to maintain occupational and public radiation doses resulting from plant operation to within the applicable limits in 10 CFR Part 20, the Design Objectives of 10 CFR Part 50, Appendix I, and ALARA.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on radiation source terms and plant radiation levels. The NRC staff concludes that the licensee has taken the necessary steps to ensure that any increases in radiation doses will be maintained as low as is reasonably achievable. The NRC staff further concludes that the proposed EPU meets the requirements of 10 CFR Part 20, and 10 CFR Part 50, Appendix I and meets the guidelines contained in Item II.B.2 of NUREG-0737. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to radiation protection and ensuring that occupational radiation exposures will be maintained as low as is reasonably achievable.

2.11 Human Performance

Regulatory Evaluation

The area of human factors deals with programs, procedures, training, and plant design features related to operator performance during normal and accident conditions. The NRC staff's human factors evaluation was conducted to ensure that operator performance would not be adversely affected as a result of system and procedure changes made to implement the proposed EPU. The NRC staff's review covered changes to operator actions, human-system interfaces, and procedures and training needed for the proposed EPU. The NRC's acceptance criteria for human factors are based on GDC 19, 10 CFR Part 50.120, 10 CFR Part 55, and the guidance in GL 82-33. Specific review criteria are contained in SRP Sections 13.2.1, 13.2.2, 13.5.2.1, and 18.0.

Technical Evaluation

The NRC staff has developed a standard set of questions for review of the human factors area. The licensee has addressed these questions in its submittal and in its response to the staff's request for additional information. Following are the staff's questions, the licensee's responses, and the staff's determination of acceptability.

1. Changes in Emergency and Abnormal Operating Procedures

Describe how the proposed EPU will change the plant's emergency and abnormal operating procedures. (SRP Section 13.5.2.1)

The licensee indicated that the existing emergency and abnormal procedures will continue to provide guidance to cover the spectrum of anticipated events. The following procedure changes are intended to enhance operator response times and to incorporate physical plant changes resulting from the EPU. Additionally, other changes, such as setpoint changes, have been identified for incorporation into several emergency, abnormal and other operating procedures.

a. Automatic action verification steps, which are included in emergency procedure E-0, "Reactor Trip or Safety Injection," will be streamlined to expedite diagnosis and plant stabilization. This modification is in accordance with a Westinghouse Owners Group (WOG) Emergency Response Guideline (ERG) Direct Work (DW) request, which was submitted by the licensee to Westinghouse, to resolve an issue related to high pressure plant response time for terminating SI flow on spurious SI actuation. The licensee's various changes to control room protocol and communications in recent years have adversely impacted the ability of the operators to complete the E-0 procedures and transition to the appropriate recovery guideline to implement the required actions in a timely manner. The licensee also considered that timeliness issues could affect other events such as SGTR. Therefore, the WOG DW request was expanded for inclusion of such events.

The WOG response to the DW request provided guidance supporting relocation of several E-0 automatic action verification steps to an attachment that can be performed, as time permits, allowing a more expeditious progression through the procedure and transition to the appropriate optimal recovery guideline. The E-0 steps 5-18, identified by the WOG guidance, were the steps involving operator verification of automatic actions after a reactor trip including operator verification of components that are used for ECCS injection. Specifically, the licensee has indicated the following verification steps will be relocated to an attachment to the E-0 procedure that a licensed operator would use concurrently with the E-0 procedure:

- SI/RHR Pumps Running
- Containment Recirculation Fans Running
- Main Steam Line Isolation
- Main Feedwater (MFW) Isolation
- SWS Pumps Running
- Containment Isolation
- Component Cooling Verification
- Check SI/RHR Flow
- SI Pump Alignment Verification
- Control Room Emergency Air Treatment System (CREATS) Actuation Verification

The licensee did not include the verification steps that involved heat sink verification and containment spray verification because operations personnel decided that the E-0 procedure should maintain the steps that verify decay heat removal capability. The reactor operator performing the steps will use a two-column formatted E-0 attachment, similar to what the senior reactor operator would use for the current E-0 procedure, in performing the verification steps. The licensee expects that this revised E-0 procedure will reduce operator action time by 2-3 minutes and allow for a faster transition to other emergency procedures. This reduced time will serve to provide operators with more time to perform actions in subsequent emergency procedures after exiting the revised E-0 procedure. The licensee plans to provide detailed training to all operating crews in using the revised E-0 procedure prior to EPU implementation so that the operators will be able to perform these verification steps along with their contingency actions. The licensee has committed to validating that the revised E-0 procedure can be performed by the operators in the reduced time before EPU implementation.

b. Functional Restoration (FR) procedure FR-H.1, “Response to Loss of Secondary Heat Sink,” will be revised to provide earlier initiation of the SAFW system to mitigate consequences of a high energy line break (HELB) in the Intermediate Building resulting in a loss of all normal AFW pumps. The SAFW system was installed for the specific purpose of mitigating a HELB that renders normal AFW inoperable. The licensee’s engineering analysis for EPU conditions showed that at least 235 gpm of SAFW flow to the intact SG must be established within 14.5 minutes. The engineering analysis projected that the RCS pressure and temperature limits would not be exceeded during that time and would not challenge the core design criteria under the current accident scenario for HELB. Currently in FR-H.1, the operators are directed to attempt to restore main feed water flow prior to initiating SAFW flow. This step was in place because the licensee preferred to use condensate grade water instead of service water to feed the SGs. The licensee considered that the actions required for initiating main feedwater flow were time consuming and that newly modified MFIVs, described in part d below, would increase the time required to establish main feedwater flow. The proposed change will direct initiation of SAFW to the SGs as the first option after normal AFW has been attempted.

c. SAFW flow requirements will increase for both the HELB event and Appendix R events that result in the unavailability of the RHR system. For the licensee’s analysis of the HELB event under EPU conditions, the SAFW is needed to provide increased flow to the SGs since the normal AFW pumps are unavailable in the intermediate building. Procedure FR-H.1, as discussed in part b, will be revised to expedite the initiation of SAFW as opposed to main feedwater flow when normal AFW is unavailable and to increase the minimum flow requirements. Regarding the licensee’s analysis of the Appendix R events, the increase of decay heat due to the EPU requires increased SAFW flow to accomplish RCS cooldown within 72 hours. The SAFW flow will be used in place of the unavailable RHR system to provide cooldown from MODE 4 to MODE 5 using water-solid SG cooldown. Procedures ER-FIRE-1, 2, and 3 (the procedures used for fires in the control room, cable tunnel, and auxiliary building basement/mezzanine) also will be revised to include the increased SAFW flow requirements.

d. The E-0 main feedwater isolation step will be changed to incorporate installation of the new MFIVs. The purpose of the new MFIVs is to assist in reducing the time required by operators to complete the MFW isolation verification step and not require the MFRVs to be closed manually before SI is reset.

e. The licensee will make changes to the RCS T_{avg} and pressurizer level program to reduce the time available for restoration of charging flow. The available time to restore charging will be reduced from 36 minutes before EPU to 24 minutes after EPU. However, the operator action to restore charging flow is currently performed within 20 minutes. The compensatory actions taken to provide operators with an additional time margin of 2-3 minutes will include a review and re-prioritization of operator actions along with two plant modifications for the charging pump, which are described below in part (h). The time available for restoring charging flow will be validated during operator training using the simulator and plant walk-throughs and the validation will take place before the EPU is implemented.

f. Guidance will be added to appropriate Appendix R procedures to initiate SI if charging is not adequate to restore pressurizer level. The purpose is to provide the licensee some additional flexibility and risk reduction since, currently, only the A charging pump is Appendix R protected.

g. Appendix R procedures will be modified to provide a contingency to ensure the capability to cooldown the pressurizer at a rate adequate to support the water-solid SG cooldown method when RHR is not available. The licensee's analysis of a fire that renders both trains of the RHR system inoperable showed that the event would require the use of water-solid SG cooldown to transition from Mode 4 to Mode 5. If the fire also results in shorting both pressurizer PORV block valves, such that they fail closed without torque switch protection, it may result in an inability to open the PORV block valves manually. This could result in the pressurizer PORVs not being available to cool down the pressurizer. The effects of the EPU could also reduce ambient heat losses that could delay pressurizer cooldown and prevent attaining cold shutdown within the 72-hour timeframe. The licensee conducted an engineering evaluation of the weak link assessment of the PORV block valves that found that the PORVs may not be available. Therefore, the licensee will utilize the pressurizer auxiliary spray as contingency action to accomplish cooldown within the required time. The licensee has committed to complete the operating procedure changes for the contingency action and conduct training prior to EPU implementation. Since the licensee has adequately shown that the cooldown can be accomplished within the required time, the NRC staff finds this acceptable.

h. Four minor modifications are being made for Appendix R local control operating stations to reduce plant risk and allow for faster operator response times. Each of the these modifications will assist the operators in responding more quickly in emergency conditions.

The installation of the new backup air supply to the charging pump speed control will allow the operators to increase charging pump speed as soon as the pump is started. The speed control for the charging pump currently depends on starting and aligning the diesel air compressor. This task was analyzed under EPU conditions to require 10-15 minutes to accomplish since the task is performed locally by an operator after several other procedure supporting tasks. The immediate ability to increase charging pump flow after pump start without requiring manual operator action to restore air provides some relief for the operator to tend to other fire mitigating tasks.

The relocation of the "A" charging pump dc control power transfer switch to the basement will eliminate the need for the local operator to travel two floors to the local bus to manipulate the power transfer switch in between making other manipulations to the "A" charging pump in the basement. The operator will only be required to go to the basement to transfer dc control power using the new power transfer switch before starting the "A" charging pump. The modification will allow the operator to restore charging in 2-3 minutes less than previously required. The time will be validated by the licensee using plant walk-throughs during the operator training prior to EPU implementation.

A modification to provide local control of the TDAFW pump discharge valve, MOV-3996, coupled with recommended procedure changes, will be made to enhance the ability of the operators to restore and control feed flow to the SGs. The valve controls will be located on the panel with the Appendix R dedicated SG level and TDAFW flow indications resulting in more efficient control.

In order to meet the requirement for capability to cooldown on both SGs for certain Appendix R scenarios, a fire hardened "B" SG level channel will be added to the local Appendix R panel. Currently, only the "A" SG has dedicated Appendix R level indication at the local panel. This is the fourth modification that is related to the Appendix R event mitigation.

i. The Emergency Plan may require minor modifications to account for additional decay heat generation, potential source term changes, and verification of severe accident management guideline (SAMG) effectiveness.

j. Setpoints related to changing balance-of-plant, generation parameters, and increased decay heat will be reviewed and revised throughout the emergency, abnormal and operating procedure sets.

The licensee is currently evaluating and revising Appendix R mitigation procedures to enhance procedural direction and to incorporate the physical plant modifications. The licensee compared the proposed procedure revisions to the existing timelines for accomplishing the Appendix R strategies and indicated that the critical operator action times will continue to be met. However, when the procedure changes are finalized by management, the licensee will conduct formal walkdowns using multiple crews to validate acceptable response times. This validation will be completed prior to operation at EPU levels.

The licensee indicates that these anticipated changes to the emergency and abnormal procedures do not alter basic mitigation strategies and will be adequately implemented by the normal procedure change process and operator training program. The procedure changes related to the above items will be validated using the licensee's training process and will be implemented prior to the EPU. The NRC staff finds the licensee's proposed changes and commitments in this area to be acceptable since the Appendix R strategies and the critical operator action times will continue to be met.

2. Changes to Operator Actions Sensitive to Power Uprate

Describe any new operator actions required as a result of the proposed EPU. Describe changes to any current operator actions related to emergency or abnormal procedures that will occur as a result of the proposed EPU. (SRP Section 18.0)

Changes to operator actions sensitive to power uprate include the following:

a. The licensee plans to reduce the time allowed for concurrent initiation of hot and cold leg recirculation to minimize boron precipitation for both an LBLOCA and SBLOCA. The NRC staff has addressed the changes to operator actions related to the EPU in the SE supporting Amendment No. 96, dated May 31, 2006 (Reference 76).

b. Reduction in the pressurizer level no-load setpoint will require increased emphasis on RCS temperature stabilization after a reactor trip to prevent letdown isolation.

c. High pressure turbine replacement may affect the turbine startup process.

d. For Appendix R scenarios requiring water-solid cool-down, the licensee will install a second spool piece in addition to the one required spool piece from the steam header to the blowdown tank to handle the increased decay heat associated with the EPU. The second spool piece would also provide the operators with more cooling capability of the water-solid SG. Installation of the spool pieces is required in preparation for SG water-solid cooldown with RHR unavailable. The licensee analyzed that SG water-solid cooldown will begin at about 50 hours after the event initiation. This would allow time for additional maintenance personnel to arrive at the plant and install the spool pieces. The installation of both spool pieces would be done in parallel, and sufficient time is available to complete installation before water-solid cooldown is needed. No new operator actions are being introduced for the installation of the second spool piece.

e. As a result of the EPU, the time for affected SG dryout is reduced from 50 minutes to 35 minutes during an Appendix R scenario. However, the existing Appendix R operator timelines for Ginna show that the feedwater flow is restored to the intact SG within 30 minutes. The licensee also plans to revise the Appendix R fire procedures to increase the efficiency of implementation by eliminating several local valve manipulations required to establish feed. These additional procedure changes will improve the operator's ability to restore SG feed within 30 minutes. The licensee has committed to use operator training prior to EPU implementation to validate that the SG feed can indeed be restored within 30 minutes.

f. In conjunction with the EPU, relaxed axial offset control (RAOC) will be implemented. This will alter the requirements for control of axial core power for steady state conditions. The RAOC implementation will provide the operator more flexibility to recover from sudden power changes and to operate within a wider band that was previously allowed by the Ginna TSs. In Amendment No. 94, dated February 15, 2006 (Reference 53), the NRC staff approved the use of RAOC at Ginna, which allows the licensee to control the axial power shape within a wider band than 5% using CAOC. Although the new procedure would not introduce any new operator actions for EPU conditions, the operators will be trained using this new procedure under EPU conditions.

The licensee has previously made programmatic changes to operator actions such as implementation of symptom-based emergency operating procedures and changes related to SG replacement and implementation of Improved TSs. These changes were accomplished using the normal plant change and training processes. The licensee considers the changes in operator actions related to the EPU to be less significant and will use the established change processes to provide an implementation strategy prior to the EPU. With the exception of the revised FR-H.1 procedure that directs initiation of SAFW when normal AFW is lost, the other changes do not significantly impact existing normal operator actions or off-normal event mitigation strategies. All of these changes will be incorporated in the procedures and the operators will receive formal classroom and simulator training for their implementation. The NRC staff finds that the changes to the operator actions are consistent with the symptom-based approach to emergency and abnormal condition responses, are adequate for the EPU conditions, and appropriate training will be conducted prior to startup. Therefore, the NRC staff finds it acceptable.

3. Changes to Control Room Controls, Displays and Alarms

Describe any changes the proposed EPU will have on the operator interfaces for control room controls, displays and alarms. For example, what zone markings (e.g. normal, marginal and out-of-tolerance ranges) on meters will change? What setpoints will change? How will the operators know of the change? Describe any controls, displays, and alarms that will be upgraded from analog to digital instruments as a result of the proposed EPU and how operators will be tested to determine they can use the instruments reliably. (SRP Section 18.0)

The licensee indicated that changes to control room controls and displays will not be extensive and will include adding controls for the two new MFIVs and expanding scales for a number of instruments. There will also be changes to control board and computer alarms and limited changes to plant control systems.

Below is a summary of the significant changes identified:

a. The following instrument loops are affected by the EPU (calibration range, scaling or transmitter changes):

- MFW flow scale
- Main Steam flow scale
- MFW pump suction flow
- SAFW pump flow
- High pressure turbine first stage pressure range
- RCS ΔT setpoint changes

b. Several Alarm Response (AR) procedures will require revision as a result of setpoint changes and changes in plant response to transients:

- MFW pump Net Positive Suction Head (NPSH) setpoint
- Steam Flow and Feedwater Flow high flow alarms
- SAFW flow alarms
- ATWS (anticipated transient without scram) mitigating system actuation circuitry (AMSAC) alarm inputs
- Condensate pump low pressure alarm
- Condensate storage tank minimum level setpoint changes
- MFW pump low suction pressure opening condensate bypass valve

c. Some Plant Process Computer System (PPCS) setpoints will be changed and new setpoints will be added for the following parameters:

- MFIV air accumulator pressure alarms
- MFW and Main Steam system alarms
- RCS ΔT alarm and protection
- RCS T_{avg}
- Pressurizer level
- Turbine first stage pressure

d. Changes to controls and control systems:

- MFIV switches and indicating lights will be added to the Control Board
- Steam Dump deadband and modulating setpoints
- Control rod speed program (power mismatch) in AUTO
- Condensate pump auto start setpoint
- Condensate heater bypass opening setpoints
- Time delay for condensate bypass valve opening
- Pressurizer level program
- RCS T_{avg} program
- Rod Bank sequencing program

e. There are no planned changes of analog to digital displays or controls. The new digital data inputs related to EPU will be encompassed to the PPCS. An example is pressure indication and alarms for the air system on the new MFIVs. The new digital data inputs to the PPCS will be informational only.

f. There is minimal application of zone banding on the Control Board. The EPU will not impact any of the zone bands currently identified on the instrumentation.

The licensee will provide operators with detailed training related to the EPU modifications and resulting control board and procedure changes. The licensee will use station modification review packages provided by engineers, who analyze and perform any new plant modifications, along with the plant operations review committee to evaluate and develop appropriate operator training related to the EPU modifications using the classroom and simulator. The initial plant startup following the EPU implementation will be conducted as a significant infrequently performed evolution (SIPE) and will be controlled by the Power Ascension Testing Plan.

The purpose of this question is to assure the staff that the licensee has adequately considered the equipment changes resulting from the EPU that affect the operators' ability to perform their required functions. Based on the licensee's response, the NRC staff is satisfied that the licensee has addressed this item acceptably.

4. Changes on the Safety Parameter Display System (SPDS)

Describe any changes the proposed EPU will have on the safety parameter display system. How will the operators know of the changes? (SRP Section 18.0)

The following changes will affect the Safety Parameter Display System:

- RCS subcooling margin to be reduced
- Condensate Storage Tank minimum required level will increase
- Critical Safety Function status trees will be reviewed and revised as necessary for related changes to setpoints and decision points

These changes will be addressed by the plant operations personnel involvement in the modification process, procedure changes, and operator training program. The licensee plans to implement these changes to the SPDS prior to EPU and through the aforementioned processes. The NRC staff finds the changes to the SPDS and commitments to implement them acceptable.

5. Changes to the Operator Training Program and the Control Room Simulator

Describe any changes the proposed EPU will have on the operator training program and the plant-referenced control room simulator, and provide the implementation schedule for making the changes. (SRP Sections 13.2.1 and 13.2.2)

The licensee currently uses Licensed/Non-Licensed Operator training programs that employ the Systematic Approach to Training (SAT) process, which has provisions for ensuring that adequate training is provided for significant plant modifications prior to implementation. This training process will focus on TS changes, procedure changes and EPU modifications. The training process began in August 2005 and has continued into subsequent training cycles. The additional training cycles, leading into 2006, focused on the general overview of the EPU modifications as well as specific training topics such as RAOC, the new HP turbine, and other plant-specific topics. The licensee is currently continuing the operator training on these topics. The licensee's 2006 training plan includes the review of the NSSS and BOP instrumentation and controls (I&C) systems, license amendments, and secondary sytems review through June 2006. Portions of training cycles 2006-01 through 2006-04 will focus on the overall EPU modifications and operations. Comprehensive training on the entire modification scope will begin during cycle 2006-05 (July through September 2006) and will include classroom and simulator training and testing on the EPU modifications. The licensee indicates that the operators will be able to demonstrate understanding of the integrated plant response on the simulator as a result of these training cycles.

Additional Just In Time (JIT) startup training will be provided to the operators during the 2006 Refueling Outage prior to the initial EPU startup. This JIT training will also cover the startup testing plan both in classroom and on the simulator as necessary. EPU modifications will be reviewed by training personnel to determine its impact on the simulator. The licensee will implement changes to the simulator modeling using a separate simulator load and using an established schedule that will meet the operator training program requirements. The simulator load for current plant configurations will remain unchanged and available for operator training. Status of the simulator configuration will be controlled through the licensee's established training process. The control board hardware changes, the addition of the MFIVs, and associated indications and replacement of indications with revised scaling, will also be scheduled by the licensee to accommodate the training program requirements.

The EPU plant modifications to the simulator will be performed using the licensee's configuration control process and will be completed prior to the scheduled operator EPU training cycles. Testing will be based on predicted performance data developed in the EPU analyses. The licensee plans to use RETRAN predictions for the ten transients required by ANSI/ANS-3.5-1998, "Nuclear Power Plant Simulators for Use in Operator Training and Examination," to benchmark simulator performance. RETRAN is the computer code used at Ginna to model the simulator for the various accident scenarios found in Chapter 15 of the Ginna UFSAR and represents the means of providing simulator fidelity for operator training. The simulator will be modified as necessary after the plant startup and additional testing, to ensure that the simulator performance is aligned with actual plant performance for subsequent operator training.

The majority of the procedure changes involve revisions related to setpoints, notes, cautions, and minor guidance enhancements. The operating procedures (a total of 15-20 identified by the licensee) will be revised to alter task sequencing and task performance. These changes will require simulator validation before the implementation of the EPU. Appendix R procedure changes that involve local manipulation will be validated by simulated walk throughs in the field. All the procedure changes will be reviewed by the Subject Matter Experts from Operations in accordance with the licensee's procedure change process. The operators will also be involved in the continuing modification review process, providing operational input and gaining knowledge of the required plant changes. The licensee will also have the Operations Department and Emergency Procedures Committee determine which of the revised procedures will require either a simulator or plant walk-through for validation.

The NRC staff is satisfied that, based on the above commitments, the licensee will develop and implement a satisfactory training program, including simulator training, for the proposed EPU.

Conclusion

The EPU results in a significant number of plant modifications that will generate changes to the proposed TSs, the operations, maintenance and testing procedures, the training simulator and the training lesson plans. All changes to the emergency operating procedures, operator actions, control room displays and alarms, SPDS, operator training, and simulator will be performed and validated by the licensee prior to EPU operation. The Ginna SAT process has previously been used to train plant personnel on significant changes, which included SG replacement and associated modifications and implementation of Improved TSs. Training for implementation of the EPU modifications will be accomplished in accordance with this process.

The NRC staff has reviewed the changes to operator actions, human-system interfaces, procedures, and training required for the proposed EPU and concludes that the licensee has appropriately accounted for the effects of the proposed EPU on the available time for operator actions and taken appropriate actions to ensure that operator performance is not adversely affected by the proposed EPU. The NRC staff further concludes that the licensee will continue to meet the requirements of GDC 19, 10 CFR 50.120, and 10 CFR Part 55 following implementation of the proposed EPU. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to the human factors aspects of the proposed system changes.

2.12 Power Ascension and Testing Plan

Regulatory Evaluation

The purpose of the EPU test program is to verify that SSCs will perform satisfactorily in service at the proposed EPU power level. The test program also provides additional assurance that the plant will continue to operate in accordance with design criteria at EPU conditions. The NRC staff's review included an evaluation of the following:

a. Plans for the initial approach to the proposed maximum licensed thermal power level, including verification of adequate plant performance,

b. Integrated plant systems testing, including transient testing, if necessary, to demonstrate that plant equipment will perform satisfactorily at the proposed increased maximum licensed thermal power level, and

c. Test program conformance with applicable regulations.

The NRC's acceptance criteria for the proposed EPU test program was based, in part, on:

a. 10 CFR Part 50, Appendix B, Criterion XI, which requires establishment of a test program to demonstrate that SSCs will perform satisfactorily in service,

b. GDC 1, "Quality Standards and Records," of Appendix A, to 10 CFR Part 50, insofar as it requires that SSCs important to safety be tested to quality standards commensurate with the importance of the safety functions to be performed,

c. 10 CFR 50.34, "Contents of applications; technical information," which specifies requirements for the content of the original operating license application including, Final Safety Analysis Report (FSAR) plans for pre-operational testing and initial operations, and

d. RG 1.68, Appendix A, Section 5, "Power Ascension Tests," which describes tests that demonstrate that the facility operates in accordance with design both during normal steady-state conditions, and, to the extent practical, during and following anticipated operational occurrences (AOOs). Specific review and acceptance criteria are contained in SRP 14.2.1.

Technical Evaluation

1. Comparison of Proposed Test Program to the Initial Plant Test Program (SRP 14.2.1, Section III.A)

Evaluation Criteria

SRP 14.2.1 Section III.A., specifies the guidance and acceptance criteria which the licensee should use to compare the proposed EPU testing program to the original power-ascension test program performed during initial plant licensing. The scope of this comparison should include (1) all initial power-ascension tests performed at a power level of equal to or greater than 80 percent of the original licensed thermal power level, and (2) initial test program tests performed at lower power levels if the EPU would invalidate the test results. The licensee shall either repeat initial power-ascension tests within the scope of this comparison or adequately justify proposed deviations from the initial power-ascension test program. The following specific criteria should be identified in the EPU test program:

- all power-ascension tests initially performed at a power level of equal to or greater than 80 percent of the original licensed thermal power level,
- all initial test program tests performed at power levels lower than 80% of the original licensed thermal power level that would be invalidated by the EPU, and
- differences between the proposed EPU power-ascension test program and the portions of the initial test program identified by the previous criteria.

Staff Evaluation

The NRC staff reviewed the following EPU test plan information provided by the licensee in order to verify that the initial EPU lapplication, supplemental information provided, and the UFSAR addressed the specific criteria for an adequate EPU test program as described above. Specifically, the following documents were reviewed during the staff's evaluation:

- FSAR Section 14, "Initial Test Program" - Provided a detailed description of the regulatory basis for the program, the initial startup test program, and the overall test objectives, methods, and acceptance criteria.
- Licensing Report
    - Section 1.0, "Introduction to the Ginna Station Extended Power Uprate Licensing Report" - Described an overview of the Ginna EPU licensing report and provided a summary of plant modifications and schedule.
    - Section 2.4.2, "Plant Operability" - Described an overview of the transients that Ginna Station must be able to sustain without initiating a reactor trip or an engineered safety feature (ESF) actuation.
    - Section 2.8.7.2, "Natural Circulation Cooldown" - Provided an evaluation of the natural circulation capability for Ginna at the EPU conditions.
    - Section 2.12, "Power Ascension and Testing Plan" - Described the test plan for the approach to the EPU power level.

- Ginna LLC letter dated September 30, 2005, “Large Transient Tests Associated with License Amendment Request Regarding Extended Power Uprate,” - Provided a final proposal for transient tests associated with the extended power uprate license amendment request.

- Ginna LLC letter dated December 6, 2005, “Response to Request for Additional Information Regarding Topics Described by Letter Dated October 25, 2005,” - Provided responses to NRC questions.

The NRC staff found that all tests described in the initial startup test program were addressed in the description of the proposed EPU test program.

Conclusion

The NRC staff concluded that the proposed EPU test program adequately identified: (1) all initial power ascension tests performed at the original licensed thermal power level, and (2) differences between the proposed EPU power-ascension test program and the initial test program.

2. Post Modification Testing Requirements for SSCs Important to Safety Impacted by EPU-Related Plant Modifications (SRP 14.2.1 Section III.B)

Evaluation Criteria

SRP 14.2.1 Section III.B., specifies the guidance and acceptance criteria which the licensee should use to assess the aggregate impact of EPU plant modifications, setpoint adjustments, and parameter changes that could adversely impact the dynamic response of the plant to anticpated operational occurences (AOOs). AOOs include those conditions of normal operation that are expected to occur one or more times during the life of the plant and include events such as loss of all offsite power, tripping of the main turbine generator set, and loss of power to all reactor coolant pumps. The EPU test program should adequately demonstrate the performance of SSCs important to safety that meet all of the following criteria: (1) the performance of the SSC is impacted by EPU-related modifications, (2) the SSC is used to mitigate an AOO described in the plant-specific design basis, and (3) involves the integrated response of multiple SSCs.

The following should be identified in the EPU test program as it pertains to the above paragraph:

- Plant modifications and setpoint adjustments necessary to support operation at EPU conditions, and

- Changes in plant operating parameters (such as RCS temperature, pressure, T_{ave}, flow, etc.) resulting from operation at EPU conditions.

Staff Evaluation

The NRC staff reviewed the planned EPU modifications and their potential effect on SSCs as documented in the license application and licensing report. In addition, the staff reviewed the responses to the RAIs dated December 6, 2005. The post-modification tests listed in Table 2.12-5, "Post Modification Testing," of the license amendment request were the acceptance tests to demonstrate design function performance and integration with the existing plant. The staff also reviewed the basis for the licensee conclusions that the modifications did not change the design function of the SSCs or the methods of performing or controlling their functions. The following modifications and post-modification test (PMT) descriptions were reviewed by the staff.

- SAFW Flow Capacity Increase - Due to the increase in decay heat, the required flow from the SAFW pump in a feed line break scenario needs to be increased from 225 gpm to 235 gpm. In addition, to meet Appendix R requirements to achieve safe shutdown in 72 hours with no RHR available, the required flow rate from the SAFW pump needs to be increased from 225 gpm to 250 gpm in order to provide a water-solid SG heat transfer. The SAFW flow capacity increase will be achieved by replacing the internal valve trim of the SAFW pump discharge valve. The PMT will consist of a channel calibration, testing of the air operated valve stroke and ASME XI testing in accordance with Section IWV, “Inservice testing of valves in Nuclear Power Plants.” Furthermore, the system capacity increase will be verified prior to exceeding 1520 MWt.

- Main Turbine - The high pressure turbine modification will consist of replacing the high pressure rotor in order to pass additional volumetric steam flow. Moreover, the high pressure turbine will require installing a new inner cylinder and modifying the inlet sleeves. The turbine control valves will also be replaced to reduce the pressure drop through the valves. The PMT will consist of a 120% rotor factory test, overspeed trip test, vibration monitoring, and thermal performance test. In addition, a turbine overspeed test will be performed during EPU startup. Valve testing will be performed during power ascension.

- Generator Instrumentation - The main generator electrical output will increase by approximately 86 MWe. The generator will be re-rated from 608.4 MVA to 667 MVA with allowable power factor of 0.92 (lagging) and 0.975 (leading). The following monitoring instrumentation was installed during the 2005 refueling outage to monitor stator winding partial discharge activity, stator winding end turn vibration, and rotor winding shorts: (1) fiber optic vibration monitoring system to be integrated into the plant process computer system, (2) flux probe and cables, and (3) partial discharge monitoring instrumentation. This installation will allow station personnel to acquire base-line performance data prior to increasing the associated output power for the uprate. The PMT consists of a channel calibration, a pre-operation electrical test and a continuity check.

  During the staff review of the PMT for the installation of monitoring instrumentation to the main generator, the staff identified a question associated with an additional PMT proposed to be performed during EPU power ascension. In the licensing report, Table 2.12-5, "Post Modification Testing," the licensee stated that installation of three generator monitoring instrumentation systems will be implemented in order to achieve the EPU rated power. As an EPU startup test for this modification, the licensee stated that the installed generator instruments will be monitored during EPU power ascension. However, the licensee stated that this testing was completed in 2005. The staff requested the licensee in an RAI to explain how this testing was completed before implementation of the EPU startup testing.

In its response to this RAI, the licensee stated that the main generator monitoring instrumentation was installed in the 2005 spring refueling outage in order to obtain baseline stator end-winding vibration, rotor circulating currents, and insulation performance. The licensee monitored this instrumentation coming out of the 2005 outage to assure it was operating properly and to collect and trend baseline data prior to the uprate. The licensee also responded that it as well will monitor this instrumentation during the EPU power ascension and will compare the data to pre-EPU data and trend throughout the operating cycle.

The NRC staff reviewed the licensee's response to this RAI and concluded that the licensee had adequately established a PMT for the main generator monitoring instrumentation that will adequately demonstrate its performance. Therefore, the staff considers this RAI to be closed.

- Main Transformer Bushing Replacement - The main transformer capacity will also be increased to meet uprate power requirements. During the 2005 refueling outage, the high voltage bushings were replaced and a fifth cooler was added to assure the transformer cooler reliability requirements. The main transformer bushing modification consisted of replacing the existing three 3000A high voltage bushings with new 3500A bushings, replacement or modification of the 3 existing high voltage bushing adaptors, installation of five new cooling assembly units, replacement of the condition monitor, including the remote monitoring capability, and refurbishment of the transformers. The PMT at completion of reassembly included: power factor and excitation check by the Doble method, turns ratio check, megger check, oil dielectric testing, dissolved gas analysis, and Furan testing.

  During the staff review of the PMT for the replacement of main transformer bushings, the staff identified several questions associated with additional PMTs proposed. The staff submitted to the licensee RAIs regarding the proposed PMTs.

  In Table 2.12-5, "Post Modification Testing," of the licensing report, the licensee stated that replacement of the main transformer bushings will be implemented in order to achieve the EPU rated power. As an EPU startup test for this replacement, the licensee stated that bushing temperature would be monitored during EPU power ascension. However, the licensee mentioned that this test was completed in 2005. The staff requested the licensee in an RAI to explain how this testing was completed before implementation of the EPU startup testing.

  In its response to this RAI, the licensee stated that subsequent to the replacement of the main transformer bushings in the 2005 spring refueling outage, the thermal response of the bushings to the power ascension to the pre-EPU full power level was compared as the post-modification test for the bushing replacement. In addition, the licensee stated that the bushings will also be monitored during the EPU power ascension to verify the bushings performance under EPU conditions.

  In Table 2.12-5, "Post Modification Testing," of the licensing report, the licensee stated that as part of the PMT for replacement of the main transformer bushings a "hydro test fire suppression system" was performed. The staff requested the licensee to provide details of why this test is part of the post modification tests when no modification description was given for this system.

In the response to this RAI, the licensee stated that as part of the main transformer bushings replacement, a fifth oil cooler was added to accommodate the additional heat load on the transformer. As a result, the licensee modified the main transformer fire suppression system to install new sprinkler heads to cover the new components of the oil cooler system. The licensee performed an in-service leak test of the fire suppression system as a pressure test of the modified sprinkler system. The leak test is an acceptable test in lieu of a hydrostatic test for the fire suppression system.

The NRC staff reviewed the licensee's response to these RAIs and concluded that the licensee had adequately established PMTs for the main transformer bushings that will adequately demonstrate its performance.

- Heater Drain System - The following heater drain system modifications will be performed to accommodate the increase in flow rate: (1) feedwater heater 1A/B normal vent system orifices will be resized; (2) an 8" heater drain tank emergency drain valve will be replaced with a larger capacity 10" valve; (3) a 1" vent line will be added from each reheater 4th pass drain level control tank to the scavenging steam near the moisture separator cycle steam inlet; and (4) a disengagement chamber (enlarged section of pipe, vented back to reheater head) for the 2nd pass reheater will be added at some place below the reheater. The PMT will consist of a channel calibration and a stroke testing of the air operated valve. In addition, heater and moisture separator reheater (MSR) drain tank levels will be monitored for stability during the power ascension.

- Condensate Storage Tank Volume Increase - The condensate storage tank overflow will be raised to provide additional tank capacity from 22500 gallons to 24350 gallons. Capacity increase needs to be provided in order to remove the integrated decay heat for at least 2 hours after a trip. The PMT will consist of inservice leak tests of the welds.

The NRC staff also reviewed the EPU modification aggregate impact analysis methodology submitted by the licensee in its application. The staff noted that analyses and evaluations had been performed for the Condition I, II, III, and IV operating transients to assess the aggregate impact of the equipment modifications and setpoint changes for EPU conditions. Condition I, II, III, and IV refers to the four categories of plant conditions, Normal Operation, Faults of Moderate Frequency, Infrequent Faults, and Limiting Faults, respectively, in accordance with the anticipated frequencies of occurrence and potential radiological consequences. Analysis inputs and models were updated as appropriate to incorporate the EPU equipment modifications and setpoint changes as well as the EPU operating conditions. Based on analyses results performed by the licensee, the plant responses to Condition I, II, III, and IV initiating events satisfied acceptance criteria.

Analyses and evaluations performed, with two exceptions, used the principal computer code LOFTRAN, which has been used in control system analyses for Ginna at current power conditions. This code has been approved by the staff and has been used for many years by

Westinghouse for accident analysis evaluations. As described in the initial licensee analysis, the plant responses to Condition I, II, III, and IV initiating events at EPU conditions are consistent with the characteristic responses based on operational and analytical experience on Ginna at the current power conditions as well as operational and analytical experience on another similar Westinghouse NSSS designed 2-loop nuclear power plants and specifically Kewaunee, which is currently operating at approximately the same power as Ginna post EPU.

The following are some of the Condition I initiating events and Condition II turbine trip transient at Ginna at EPU conditions analyzed using the LOFTRAN computer code:

- Step load increase of 10% of full power from 90% to 100% power
- Step load decrease of 10% of full power from 100% to 90% power
- Large load rejection of 50% of full power from 100% power
- Turbine trip without reactor trip initiated from P-9 setpoint (49% power)
- Turbine trip from 100% power

The two exceptions in which LOFTRAN was not used are for the Condition IV LBLOCA where the BELOCA methodology and WCOBRA/TRAC computer codes were used, and for the Condition II Non-LOCA transients where RETRAN and VIPRE computer codes were used. All of these computer codes have been approved by the staff and are used in the analyses of Condition II, III, and IV initiating events for other Westinghouse NSSS designed nuclear power plants. As described in the initial licensee analysis, the dynamic plant responses to these two exceptions at EPU conditions with the EPU equipment modifications and setpoint changes are consistent with their characteristic responses based on operational and analytical experience at other similar Westinghouse designed 2-loop nuclear power plants and specifically Kewaunee, which is currently operating at approximately the same core thermal power as Ginna post EPU.

Conclusions

The NRC staff concluded, based on review of each planned modification, the associated post-maintenance test, and the basis for determining the appropriate test, that the EPU test program will adequately demonstrate the performance of SSCs important to safety and included those SSCs which are: (1) impacted by EPU-related modifications, (2) used to mitigate an anticipated operational occurrence described in the plant design basis, and (3) supported a function that relied on integrated operation of multiple systems and components.

The staff concluded that the proposed test program adequately identified plant modifications and setpoint adjustments necessary to support operation at the uprated power level and changes in plant operating parameters (such as reactor coolant temperature, pressure, T_{ave}, reactor pressure, flow, etc.) resulting from operation at EPU conditions. Additionally, the staff determined there were no unacceptable system interactions because of modifications to the plant.

3. Justification for Elimination of EPU Power-Ascension Tests (SRP 14.2.1, Section III.C)

Evaluation Criteria

SRP 14.2.1 Section III.C., specifies the guidance and acceptance criteria the licensee should use to provide justification for a test program that does not include all of the power-ascension testing that would normally be considered for inclusion in the EPU test program pursuant to the review criteria of Sections 1 and 2 above. The proposed EPU test program shall be sufficient to demonstrate that SSCs will perform satisfactorily in service. The following factors should be considered, as applicable, when justifying elimination of power-ascension tests:

- previous operating experience,
- introduction of new thermal-hydraulic phenomena or identified system interactions,
- plant staff familiarization with facility operation and trial use of operating and emergency operating procedures,
- margin reduction in safety analysis results for anticipated operational occurrences, and
- risk implications.

Staff Evaluation

The NRC staff reviewed Table 2.12-3, "Comparison of Proposed EPU Test to Original Startup Tests," in the licensing report, and the responses to the RAIs dated December 6, 2005.

During the staff review of the test program for the EPU startup test submitted in the licensing report, the staff identified several questions associated with justifications for eliminating normal power-ascension tests.

In Table 2.12-3, Startup Test Number SU 4.2.7, "Pressurizer Level Control Test," the licensee stated that this test is not planned for the proposed EPU startup test plan. This test verifies the setpoints of the pressurizer level control system and determines how the system responds to system level and Tavg variation. The licensee is changing the level setpoints of the pressurizer as part of the plant modifications that will be implemented in order to achieve the EPU rated power. The licensee stated that the new setpoints will be verified by instrument calibration checks prior to startup. In addition, the licensee stated that the performance of the level control system with changes in power level will be verified during power escalation and transient tests. The staff requested the licensee in a RAI to provide additional justification, as to why the Pressurizer Level Control Test does not needed to be performed as part of the EPU startup test plan. Specifically, the staff requested the licensee to specify the transient tests that will be performed and the performance verification of the level control system of those transients.

In response to this RAI, the licensee stated that two transient tests will be performed to verify the performance of the pressurizer level control system. The first transient test that the licensee will perform is a 10% load ramp test, both down and up at 1% per minute, at 30% and 100% EPU power. This test will result in a ramp change in the pressurizer program level as a result of the change in reactor power and coolant temperature. The test will verify that the actual program pressurizer level tracks as expected with changes to program pressurizer level.

The second transient test that the licensee stated that will be performed to verify the performance of the pressurizer level control system is a manual turbine trip from approximately 30% power. This test will cause a rapid change in program level as a result of a rapid change in reactor power from approximately 30% to 10%. The licensee will be monitoring the actual pressurizer level response and will compare the results with the expected change in program level.

The NRC staff reviewed the licensee's response to this RAI and concluded that the licensee had adequately established a verification of the pressurizer level control system that will adequately demonstrate its performance. The staff agrees with the licensee's decision that the Pressurizer Level Control Test does not needed to be performed as part of the EPU startup test plan.

In Table 2.12-3, Startup Test Number SU 4.9.2, "Steam Dump Test," the licensee stated that this test is not planned for the proposed EPU startup test plan. This test optimizes the setting of the steam dump controller. The licensee is changing the steam dump setpoints as part of the plant modifications that will be implemented in order to achieve the EPU rated power. The licensee stated that the new setpoints will be verified by instrument calibration checks prior to startup. In addition, performance of the steam dump system will be verified during transient tests. The staff requested the licensee in an RAI to provide additional justification, as to why the Steam Dump Test does not need to be performed as part of the EPU startup test plan. The staff requested the licensee to specify the transient tests that will be performed and the performance verification of the level control system of those transients.

In response to this RAI, the licensee stated that the steam dump controller operation in the pressure control mode will be verified during initial power ascension before the main generator is online, and while synchronizing the main generator to the grid. During this evolution, steam demand is controlled manually with steam dumps by adjusting the pressure control signal and increasing steam demand to approximately 20% reactor power just prior to synchronizing. When the main generator is synchronized, the steam dumps will close in response to a lowering steam pressure signal as the main turbine picks up load. The steam dump valves position and pressure control performance will be verified during this evolution.

The second transient test that the licensee stated that will be used to verify the performance of the steam dump control system is a manual turbine trip from approximately 30% power. The licensee stated that a rapid change in reactor power from approximately 30% to 10% will cause a rapid opening of the steam dump valves and modulation of the valves over time to maintain average reactor coolant temperature at approximately 547 EF. The licensee will verify the dynamic response of the steam dump system during this test.

The staff reviewed the licensee's response to this RAI and concluded that the licensee had adequately established a verification of the steam dump system that will adequately demonstrate its performance.

In the application, the licensee stated that operating experience had been incorporated into the proposed test plan. However, the licensee did not provide information in the license amendment request of specific operating experience incorporated into their proposed test plan. The NRC staff requested in an RAI that the licensee to provide additional information regarding specific examples of operating experience incorporated into the proposed test plan.

In December 6, 2005, and February 16, 2006, letters, the licensee provided information of lessons learned from industry operating experience with power uprates that will be incorporated in a number of ways to facilitate and enhance the power uprate implementation (e.g., test scope, operator training, and procedure development). Specifically, as a result of industry experience related to vibration following power uprates, the licensee is enhancing the vibration monitoring program to include monitoring of components that had problems due to vibration induced fatigue and branch lines attached to lines that could be affected due to an increase in process fluid.

The NRC staff reviewed the licensee's response to this RAI and concluded that the licensee had adequately examined industry operating experience associated with power uprates and provided appropriate information on the incorporation of the operating experience into their proposed test plan.

The NRC staff also reviewed Section 2.12.1.2.7, "Justification for Exception to Transient Testing," of the licensing report. The staff reviewed the following technical justifications for not performing large transient testing, as provided by the licensee.

- +/- 10% Step Load Change Test - The purpose of the +/-10% step load change test during the initial startup test program was to verify plant control system response to small but rapid load changes. The test verified the ability of the pressurizer level and pressure control system to maintain parameters within design limits and provide for stable plant operation. An analysis of a +/-10% step load change was performed using the LOFTRAN code. The LOFTRAN analysis inputs and models were updated as appropriate to incorporate EPU-related changes to parameter and setpoint values.

  The 10% step-load decrease transient is intended to avoid reaching the pressurizer power-operated relief valve (PORV) setpoint. The results indicated that no reactor trip setpoints were challenged and the control system response was stable and not oscillatory. Pressurizer pressure reached a maximum of 2317 psig for the high Tavg case which is less than the 2335 psig PORV setpoint. Therefore, the plant response for the 10% step-load decrease transient is acceptable for the EPU.

  The 10% step-load increase transient was analyzed to verify that there is adequate margin to the low pressurizer pressure reactor trip setpoint and the engineered safety features actuation function on low steamline pressure. The control system response was smooth during the transient with no oscillatory response noted. No reactor trip or ESF actuation setpoints were challenged. The steam pressure reached a minimum of approximately 613 psig (lead/lag compensated), which is greater than the low steamline flow SI actuation setpoint of 514 psig. The minimum pressurizer pressure reached was approximately 2203 psig, which is greater than the low pressure reactor trip setpoint of 1873 psig. Pressurizer level dropped to approximately 36% of span due to the cooldown, which is well above the low-level heater cutoff setpoint of 13% of span. The low T_{avg} value reached was approximately 560 EF and is above the low T_{avg} setpoint of 545 EF. Therefore, the plant response for the 10% step-load decrease transient is acceptable for the EPU.

  The analyses demonstrated that Ginna response to +/-10% step load changes at EPU conditions are acceptable.

- Electrical Load Loss from Below 50% Power Test and Loss of 50% Load at 75% and 100% Power Tests - The net electrical load loss from below 50% power and the loss of 50% load at high power are tests to demonstrate that the control systems act together to prevent a reactor trip and also prevent the opening of the main steam safety valves (MSSVs). In particular, the test demonstrates that the rod control, steam dump and pressurizer pressure and level control systems act together to control the NSSS response to within design limits and the reactor trip setpoints. An analysis of a 50% step load reduction from below the P-9 setpoint (49%) and from 100% EPU power were performed using the LOFTRAN code.

  Based on the results of the analyses using the revised rod control and steam dump setpoints, a 50% rapid load reduction at a turbine runback of 200% per minute can be sustained for full-power T_{avg} values of 564.6 EF and above. The PORVs will open for all cases analyzed and limit the pressurizer pressure. The peak pressurizer pressure was controlled by the pressurizer PORV actuation at the PORV actuation setpoint value of 2335 psig, thereby preventing the pressurizer pressure from reaching the high pressurizer pressure reactor trip setpoint of 2377 psig and showing acceptable capacity for the pressurizer PORVs. The minimum predicted pressure of all the cases analyzed is approximately 2002 psig, therefore the low-pressurizer pressure reactor trip setpoint of 1873 psig is not challenged. During the transient, pressurizer level remained less than the pressurizer high level trip setpoint of 87% for both the low T_{avg} (66.7%) and the High T_{avg} (83%) cases. These analyses demonstrate that the Ginna plant response to 50% step load decrease at EPU conditions will not cause a reactor trip and will not cause the MSSVs to open.

  Based on the above analysis and the avoided risk of an unnecessary plant transient, a step load reduction of 50% from below the P-9 setpoint and from 100% EPU power to verify proper operation of the plant and automatic control systems is not required in the Ginna EPU Power Ascension Test Plan.

- Manual Turbine Trip from 100% Power Test - During the NRC staff review of the test program for the EPU startup test, the staff identified a question associated with justification for eliminating this transient test. The staff submitted to the licensee an RAI regarding the deviations from the initial power-ascension test program. A response was requested for information related to the following:

  In licensing report Section 2.12, “Power Ascension and Testing Plan,” under the specific justification for not performing Manual Turbine Trip from 100% Power Test, the licensee referenced Section 2.4.2, “Plant Operability.” The licensee stated that Section 2.4.2 described an analysis of a turbine trip from 100% EPU power using the LOFTRAN code. However, the staff reviewed Section 2.4.2 and did not find information relating to manual turbine trip from 100%. The staff requested the licensee in the RAI to provide information on the description of analyses and evaluations relating to manual turbine trip from 100% power.

  In response to this RAI, the licensee provided the description of analyses and evaluations relating the manual turbine trip from 100% power. The purpose of this test was to demonstrate that all control systems will operate as expected when a turbine step load decrease from 100% to 0% power was performed followed by a reactor trip at approximately 0.3 seconds after the turbine trip. The test would also demonstrate that the plant will return to no load condition. The test was performed using the LOFTRAN thermal hydraulic code. The results of these analyses and evaluations demonstrated the following:

< The pressurizer PORVs will not actuate

< The SG PORVs will not actute

< The SG safety valves are not challenged

< The pressurizer safety valves are not challenged

< The steam dump capacity is adequate for mitigation of this transient

< The safety injection will not actuate

Based on the results of analytical and computer code modeling, a Manual Turbine Trip from 100% Power Test is not required in the Ginna EPU Power Ascension Test Plan.

The NRC staff reviewed the licensee's response to this RAI and concluded that the licensee had adequately demonstrated an analysis to verify the plant response to a Manual turbine Trip from 100% power. Therefore, the staff finds the response to this RAI to be satisfactory.

- Natural Circulation Test - The purpose of the natural circulation test is to demonstrate the capability of natural circulation to remove core decay heat while maintaining NSSS parameters within design limits. The test was performed at 2% power and demonstrated that natural circulation flows were adequate to remove heat and maintain NSSS parameters in an acceptable range.

  The natural circulation behavior for Ginna is essentially unchanged for EPU conditions. Core outlet temperatures remain bounded by full power operating conditions and subcooling is adequate. Additionally, the licensee's response to GL 81-21 stated a commitment for a training program on the procedures for natural circulation cooldown. Based on the results of analytical and computer code modeling, a natural circulation test is not required in the Ginna EPU Power Ascension Test Plan.

The staff identified additional questions associated with justifications for eliminating tests. In RAIs to the licensee, the staff had questions regarding the deviations from the initial power-ascension test program. The staff requested information as described below.

In the EPU licensing report, the licensee stated, as a justification for eliminating transient tests, that the LOFTRAN computer code results are consistent with experience on several similar Westinghouse-designed 2-loop nuclear power plants that use LOFTRAN computer code for analysis. However, the licensee did not provide information in the license amendment request of real operating experience that proved the predicted response of the LOFTRAN code was consistent with previous power uprates. The staff requested in a conference call that the licensee provide additional information regarding examples of operating experience from other operating plants that used the same analytical computer code that showed that the transient experience operated as predicted after the power uprate.

In a letter dated February 16, 2006, the licensee provided two different examples where plant performance during the event was comparable to the LOFTRAN prediction. The licensee provided Kewaunee as one example. On November 28, 2005, Kewaunee lost one main feedwater pump while operating at full power that led to a reactor trip. During the real event as predicted by the LOFTRAN code, no pressurizer safety valves or SG safety valves opened, and no safety injection actuation occurred. Additionally, the event confirmed the capability of the control rod and turbine control system to reduce the core power.

In addition to the Kewaunee event, the licensee mentioned a reactor trip that occurred at Farley after its power uprate, on May 27, 1999. Farley's event was initiated by the loss of a feedwater pump and the reactor tripped. Again, as predicted by the LOFTRAN code, no safety valve opened, no safety injection occurred and the plant stabilized at no-load temperature due to proper control system operation.

The NRC staff reviewed the licensee's response to this RAI and concluded that the licensee had adequately provided operating events that confirm that the LOFTRAN computer code can predict plant performance during transients after power uprates. Therefore, the staff finds the response to this RAI to be satisfactory.

In licensing report Section 2.12, "Power Ascension and Testing Plan," the licensee did not provide information of plant staff familiarization with facility operation and trial use of operating and emergency operating procedures. The staff requested the licensee in an RAI to provide information of any plant staff familiarization with facility operation and trial use of operating and emergency operating procedures associated with the proposed EPU test program.

In response to this RAI, the licensee stated that licensing report Section 2.11, "Human Performance," provides an overview of training for the plant staff. The licensee will evaluate the operator requirements as part of the procedure changes process requirements. Significant changes would typically require both classroom and simulator training. The plant modification and procedure change process also require that training curriculum committees for other appropriate disciplines consider training requirements for the specific changes.

The licensee is also performing familiarization training. The licensee is providing a general overview training for the EPU to the operators and Shift Technical Advisors. The 2006 training cycles in the first two quarters will provide high level overview training. In the two training cycles prior to the 2006 outage, the licensee will conduct an intense block of EPU training, including both simulator and classroom. During these two training cycles, the licensee will exercise the emergency and off-normal procedures on the simulator. Finally, the licensee will include simulator training for plant start up during the 2006 RFO, operator "just in time" training.

The staff reviewed the licensee's response to this RAI and concluded that the licensee had adequately established a plant staff familiarization training program including facility operation and trial use of operating and emergency operating procedures associated with the proposed EPU test program. Therefore, the staff considers this RAI response to be satisfactory.

The staff found that although risk implications were discussed in justifying elimination of tests, risk was not the sole factor used to determine test elimination. Other factors used to determine EPU test elimination included use of baseline operational data, updated computer modeling analyses, and industry experience.

In the initial evaluation of the original Ginna startup test program and recommendations from the NSSS vendor, the licensee concluded that no large transient tests needed to be performed as part of the EPU test program. However, due to the number of modifications made to the balance of plant systems to accommodate EPU power levels, the licensee evaluated the performance of additional transient tests beyond those described in the license amendment dated July 7, 2005. The licensee provided supplemental information of the results in a letter dated September 30, 2005. The purpose of this detailed evaluation was to verify that no new adverse system interactions or thermal hydraulic phenomena have been introduced to plant systems as a result of the EPU modifications and verifying integrated plant performance against the potential adverse plant risk associated with an unwanted transient.

In a letter dated September 30, 2005, the licensee concluded that a manual turbine trip test at approximately 30% EPU power will be performed as part of the power escalation test plan. The purpose of the test is to verify the plant's dynamic transient response and control system settings. The test will exercise control systems such as rod control, steam dump control, pressurizer level and pressure control, and SG water level control. The test will verify the manner in which the control systems respond to the power and temperature mismatch as result of a turbine trip. The acceptance criteria for this test will include: (1) verification that no reactor trip occurs, (2) that the pressurizer safety valves, main steam safety valves and pressurizer PORVs do not open, and (3) that the plant dynamic response is stable and converging on a range that supports safe operation at low power.

In addition, the manual turbine trip at 30% EPU power will provide transient response data that the licensee will use when necessary and appropriate to tune both the simulator and engineering design models. The test will provide the licensee opportunity to gain operator experience with a load rejection transients under controlled conditions that will then be used to adjust operating procedures when necessary and appropriate.

The licensee will establish procedural criteria to initiate operator manual control if malfunction of equipment is apparent in order to mitigate the impact on overall plant risk. In addition, calibration checks and post-modification testing of control systems will be conducted prior to the test. Finally, the licensee will not perform the test if the transmission operator requests not to perform the test (e.g., system demands), if the risk management analysis consistent with 10 CFR Part 50.65 (a)(4) show that the risk of the test is significant (e.g., severe weather), or if a plant transient occurs prior to performance of the test (e.g., manual turbine trip due to other reasons), which successfully verifies the objectives of this test.

Conclusions

The NRC staff concluded that in justifying test eliminations or deviations, the licensee adequately addressed factors which included previous operating experience, introduction of new thermal hydraulic phenomena or system interactions, and staff familiarization with facility operation and use if operating and emergency operating procedures. The staff noted that although qualitative risk implications were considered, in no instance did the licensee depend primarily or solely on risk as the basis for not performing the large transient tests. The staff determined that the licensee did not rely on analytical analysis as the sole basis for elimination of a power ascension test from the proposed EPU test program. Construction, installation and/or pre-operational testing for each modification will be performed in accordance with the plant design process procedures. The final acceptance tests will demonstrate the modifications will perform their design function and integrate appropriately with the existing plant. In addition, the staff finds that performing the manual turbine trip at 30% is appropriate and will provide reasonable assurance that the plant will operate in accordance with design criteria without an increase in the overall plant risk.

4. Adequacy of Proposed Testing Plans (SRP 14.2.1 Section III.D)

Evaluation Criteria

SRP 14.2.1 Section III.D., specifies the guidance and acceptance criteria the licensee should use to include plans for the initial approach to the increased EPU power level and testing that should be used to verify that the reactor plant operates within the values of EPU design parameters. The test plan should assure that the test objectives, test methods, and the acceptance criteria are acceptable and consistent with the design basis for the facility. The predicted testing responses and acceptance criteria should not be developed from values or plant conditions used for conservative evaluations of postulated accidents. During testing, safety-related SSCs relied upon during operation should be verified to be operable in accordance with existing TSs and quality assurance program requirements. The following should be identified in the EPU test program:

- the method in which initial approach to the uprated EPU power level is performed in an incremental manner including steady-state power hold points to evaluate plant performance above the original full-power level;

- appropriate testing and acceptance criteria to ensure that the plant responds within design predictions including development of predicted responses using real or expected values of items such as beginning-of-life core reactivity coefficients, flow rates, pressures, temperatures, response times of equipment, and the actual status of the plant;

- contingency plans if the predicted plant response is not obtained; and

- a test schedule and sequence to minimize the time untested SSCs important to safety are relied upon during operation above the original licensed full-power level.

Staff Evaluation

The NRC staff reviewed Section 2.12 of the licesning report, which described power ascension tests as they related to the proposed EPU implementation. The staff found that the licensee adequately addressed EPU operating experience for a similar designed plant, specifically Kewaunee, in determining the current proposed test plan for Ginna. The staff also found:

- Determination of the proposed tests and test plan addressed the effects of any new thermal-hydraulic phenomena or system interaction that may be introduced by the EPU through computer model analyses and/or operating plant experience.

- The plant staff, through classroom and/or simulator training, will be familiarized with the operation of the plant under EPU conditions. The training will include plant modification and setpoints changes, implementation of normal, off-normal, and emergency procedures, and accident mitigation strategies.

- Risk informed justifications for not performing transient tests were considered but not the sole factor in determining elimination of those tests. Previous operating experience, the initial startup test program report, and computer model analyses were the major influences on those decisions.

During the EPU start-up, power will be increased in a slow and deliberate manner, stopping at pre-determined power levels for steady-state data gathering and formal parameter evaluation. The typical post-refueling power plateaus will be used until the current (pre-EPU) full power condition is attained at approximately 85% of the EPU power level (1520 MWt), with additional equipment and plant transient testing performed at 25% and 50% of the EPU power level to verify expected component, system and integrated plant performance.

Prior to exceeding the current licensed core thermal power of 1520 MWt, the steady-state data gathered at the pre-determined power plateaus and transient data gathered during the specified transient tests at low power, as well as observations of the slow, but dynamic power increases between the power plateaus, will allow verification of the performance of the EPU modifications. In particular, by comparison of the plant data with pre-determined acceptance criteria, the test plan will provide assurance that unintended interactions between the various modifications have not occurred such that integrated plant performance is adversely affected.

Once at approximately 85% of EPU power (1520 MWt), power will be slowly and deliberately increased through 5 additional power plateaus, each differing by approximately 3% of the EPU RTP. Again, both dynamic performance during the ascension and steady-state performance for each test condition will be monitored, documented and evaluated against pre-determined acceptance criteria.

The licensee plans implementation of the majority of the modifications and setpoint changes for the 2006 refueling outage. Four modifications were completed in the 2005 refueling outage. Power escalation to the new power level is planned immediately after the 2006 refueling outage. The staff noted that Ginna will follow typical startup procedures and TS requirements when the EPU is implemented.

Conclusions

The NRC staff concluded that the proposed test plan will be performed by qualified personnel and will adequately assure that the test objectives, test methods, and test acceptance criteria are consistent with the design basis for the facility. Additionally, the staff concluded that the test schedule would be performed in an incremental manner, with appropriate hold points for evaluation, and contingency plans existed for if predicted plant response is not obtained.

Summary Conclusion

The NRC staff has reviewed the EPU test program in accordance with SRP Section 14.2.1. This review included an evaluation of (1) plans for the initial approach to the proposed maximum licensed thermal power level, including verification of adequate plant performance, (2) transient testing necessary to demonstrate that plant equipment will perform satisfactorily at the proposed increased maximum licensed thermal power level, and (3) the test program's conformance with applicable NRC guidance. For the reasons set forth above, the staff concludes that the proposed EPU test program provides reasonable assurance that the plant will operate in accordance with design criteria and that SSCs affected by the EPU or modified to support the proposed power uprate will perform satisfactorily while in service. On this basis, the staff finds that the EPU testing program satisfies the requirements of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control." Therefore, the NRC staff finds the proposed EPU test program acceptable.

2.13 Risk Evaluation

2.13.1 Risk Evaluation of Extended Power Uprate (EPU)

Regulatory Evaluation

The licensee conducted a risk evaluation to: (1) demonstrate that the risks associated with the proposed EPU are acceptable and (2) determine if "special circumstances" are created by the proposed EPU. As described in Appendix D of SRP Chapter 19, special circumstances are present if any issues are identified that would potentially rebut the presumption of adequate protection provided by the licensee in meeting the deterministic requirements. The NRC staff's review, for this section of the application, covered the impact of the proposed EPU on core damage frequency (CDF) and large early release frequency (LERF) for the plant, due to changes in the risks associated with internal events, external events, and shutdown operations. In addition, the NRC staff's review covered the quality of the risk analyses used by the licensee to support the application for the proposed EPU. This included a review of the licensee's actions taken to address issues or weaknesses that may have been raised in previous NRC staff reviews of the licensee's individual plant examinations (IPEs) and individual plant examinations of external events (IPEEEs), or by an industry peer review. The NRC's risk acceptance guidelines, which are contained in RG 1.174, apply to risk-informed changes, but can also be used for non-risk-informed applications as one element in providing insights into the impact to adequate protection from implementation of the application. Specific, risk-related, review guidance for EPU applications is contained in Matrix 13 of Review Standard RS-001 and its attachments to aid in the determination of whether special circumstances exist with respect to a specific, non-risk-informed, issue.

Technical Evaluation

The Ginna Probabilistic Safety Analysis (GPSA) covers internal events, external events, and shutdown operations. The licensee's risk evaluation used the GPSA to compare the risks of the pre-EPU to the post-EPU plant design and operation. A combination of quantitative and qualitative methods was used to assess the risk impacts of the proposed EPU. The following sections provide the staff's technical evaluation of the risk information provided by the licensee.

1. Probabilistic Risk Assessment (PRA) Model Quality

The Ginna internal events, Level I, and Level II PSA was initially developed in response to NRC Generic Letter 88-20 (IPE). External events were also addressed as part of the IPEEE program. The GPSA model has undergone several revisions since the original IPE and IPEEE to incorporate improvements and maintain consistency with the as-built, as-operated plant.

Revision 5.0 of the GPSA model involves extensive revision and upgrade of human reliability analysis (HRA), along with enhancements to thermal-hydraulic analysis, fire modeling, SG tube rupture (SGTR) modeling, and SBO modeling. In addition, the reactor coolant pump (RCP) seal LOCA modeling was revised to be consistent with the current Westinghouse PRA guidance on RCP seal LOCA modeling (WCAP-16141).

The Westinghouse Owners Group (WOG) performed a peer review of the GPSA Revision 4.1 model in May 2002. This peer review resulted in 6 A-Level, and 35 B-Level, facts and observations (F&Os). A-Level F&Os are defined as being extremely important and necessary to address in order to assure the technical adequacy of the PSA, while B-Level F&Os are defined as being important and necessary to address, but may be deferred until the next PSA update. The licensee provided a summary of the A-Level and B-Level F&Os and their resolutions. Nearly all of the identified F&Os have been addressed by the licensee. Only two, B-Level F&Os have not been fully addressed. The licensee stated that these two F&Os were reviewed to assure that they do not affect the estimated risk impact of the planned power uprate.

The first B-Level F&O is related to the complexity of the GPSA model due to using the same top logic fault tree to address all events, including fires, floods, shutdown, spent fuel pool, and fuel handling accidents. In the process of the peer review, the team identified three (and possibly four) logic gate errors and suggested that the licensee simplify the logic for review and perform a systematic review of the entire logic structure. The licensee indicated that they had performed a significant review of the model logic and corrected the identified errors as part of subsequent PSA revisions (4.2, 4.3, and 5.0), in addition to checking the correctness of the PSA cutsets. For the EPU, the license reviewed parts of the fault tree logic associated with EPU impacts to ensure correctness and evaluated cutset results.

The second B-Level F&O is related to the limited level of documentation detail that made it difficult for the peer review team to resolve some questions. Many of these comments could be resolved by providing available documentation that the reviewers were unaware of during the peer review. The peer review team's specific observations included two comments related to potential model errors. The modeling errors were corrected by the licensee and the only remaining aspects of the F&O relates to documentation, which will require the licensee to enhance their documentation.

The NRC staff has evaluated the peer-review F&Os and the licensee's associated resolutions, including the two outstanding B-Level F&Os, and concurs with the licensee's assessment that there should be no significant impact on the EPU evaluations from the outstanding B-Level F&Os. The staff finds that the licensee has met the intent of RG 1.174 (Sections 2.2.3 and 2.5) and SRP Chapter 19.1 and that the GPSA model has sufficient scope, level of detail, and technical adequacy. Therefore, the staff finds that the GPSA, as described above, is adequate to support its application for the EPU.

2. Internal Events (Level I)

The risk impacts of the proposed EPU due to internal initiating events were assessed by the licensee by reviewing the changes in plant design and operations resulting from the proposed EPU, mapping these changes onto appropriate PSA elements, modifying affected PSA elements, as needed, to capture the risk impacts of the proposed EPU, and requantifying the GPSA to determine the CDF and LERF of the post-EPU plant. It is noted that the licensee's results are based on a cutset truncation level of 1E-10/year. As a result of EPU, the licensee estimated approximately a 16% increase in internal events CDF (from about 1.3E-5/year to about 1.5E-5/year) and a 19% increase in internal events LERF (from about 1.3E-6/year to 1.5E-6/year).

The licensee's assessments included evaluations of EPU impacts on the following areas, as described below.

- Initiating event frequency,
- Success criteria,
- Operator response times,
- Component and system reliability, and
- Overall impact on CDF and LERF

a. Internal Initiating Events Frequencies

The GPSA addresses LOCA, SGTR, loss of offsite power (LOOP), transient initiators, and internal flooding. The licensee reviewed these initiators to assess the potential effects of the power uprate on their frequencies.

In the case of LOCA, the licensee stated that EPU does not involve changes to the reactor coolant system (RCS) piping, or interfacing systems piping, and concluded that LOCA frequencies are not affected by EPU. However, a LOCA can occur as a result of an RCS pressure excursion that results in a stuck-open power-operated relief valve (PORV) or primary safety relief valve. For example, a loss of electrical load can result in a turbine overspeed challenge, which will also cause a PORV and main steam safety valve (MSSV) challenge. For EPU, the licensee increased the frequency of a PORV or MSSV challenge, with attendant probability of sticking open, based on Ginna-specific experience data, an estimated loss of load profile, and engineering judgment to provide insight into the impact of changes in PORV/MSSV challenges.

In the case of SGTR, Ginna installed RSGs in 1996 that have more tubes, resulting in increased surface area, which allows higher power generation. The RSGs are constructed using Alloy 690 material, which will reduce corrosion effects, and which include construction features that control vibration resonance. The licensee performed flow-induced vibration analyses to conclude that no adverse impact is expected from the EPU. In addition, the increased heat associated with EPU is expected to result in an increase in steam flow during normal operations and after a plant trip. As a result, the time to overfill, given an SGTR, is expected to be longer. For this evaluation, the licensee assumed the recovery time available for steam generator overfill scenarios was the same pre-EPU and post-EPU. As a result, the licensee concluded that the existing (recently modified) STGR model is applicable to EPU conditions.

In the case of LOOP, the licensee found that the EPU does not necessitate replacement or modification of the switchyard breakers or disconnects. In a normal switchyard/plant configuration, all switchyard equipment will operate within design limits, but it was noted that certain switchyard/plant configurations may require a small load reduction to maintain equipment within operational limits, which will be administratively controlled. The licensee also mentioned that the generator step-up (GSU) transformer, and associated cables connecting the GSU to the switchyard, will be upgraded to handle the increased power. It was also stated that, due to LOOP frequency correlation with switchyard grid reliability, the New York Independent System Operator agreed that overloads, created by the unanticipated loss of some circuits increasing the load on the remaining circuits, can be mitigated through various operational techniques. To address unforeseen switchyard reliability issues, the licensee increased the LOOP frequency by 10%, based on engineering evaluation reports that included considerations of the reduction in operating margin of the identified equipment.

For transient events, the licensee determined what components or system changes could impact the likelihood of a reactor trip. As expected, the reactor protection system trip setpoints, and those of the control systems, need to be changed in order to accommodate a number of operational transients without generating a reactor trip. Some control room instrumentation will also be rescaled to meet the EPU conditions. In addition, the increased power output will result in some loss of operating margin for the main generator and some operating plant equipment will operate closer to trip setpoints or capacity limits, causing a reduction in margin. Engineering evaluations were performed by the licensee that resulted in an estimated increase in reactor trip frequency by 20%.

Electric distribution systems (e.g., 125 volt (V) direct current, 4160 V alternating current (ac), and 120 Vac were investigated and the licensee concluded that only a slight increase, or no change, in these initiator frequencies is anticipated.

In the case of the service water system (SWS), its heat loads will increase as a result of the EPU. The licensee stated that the SWS will continue to provide the required heat removal capability at EPU conditions and that the increase in flow required of SWS as a source of AFW, is considered insignificant with regards to the SWS design and capacity. The licensee also stated that no substantive changes are expected in the frequencies of loss of component cooling water and loss of instrument air.

For EPU, the main feedwater (MFW) system, main steam system, and extraction steam system will operate at increased flow rates. The licensee plans to increase the existing capacity by replacing the motors and impellers of the condensate booster pumps and MFW pumps to support the EPU. Other changes are also planned (e.g., regulating valves) to support the EPU. Further, the licensee stated that some turbine building feedline pipe segments, and several turbine building extraction steam pipe segments, exceed industry standards for flow velocity. The licensee increased the feedline and steamline break frequencies to address these conditions and identified those pipe segments for inclusion in the licensee's Corrosion/Erosion Program. To address operational changes that impact these systems, the licensee performed engineering evaluations to identify components that can potentially have reduced operating margin, which would result in increasing the initiator frequencies for loss of MFW, feedline breaks in the turbine building, and extraction steamline breaks in the turbine building by 40 percent. The frequency of an induced steamline break through the steam dump system, due to the tighter instrument tolerances required for EPU, was increased by 10%.

For internal flooding events, the licensee concluded that, other than as a consequence of the initiators discussed above that involve pipe breaks, there are no substantive changes to other systems that may induce internal flooding. Thus, the flooding initiator frequency is expected to remain unchanged.

For anticipated transient without scram (ATWS) events, the post-EPU moderator temperature coefficient (MTC) will be more negative than that of pre-EPU throughout the cycle, due to increased boration levels. However, the relief capacity of the PORVs, MSSVs, and atmospheric relief valves, relative to thermal power, is lower with EPU. Recognizing that EPU conditions will have greater AFW/MFW flow and more negative MTC, the licensee expects ATWS mitigation capability to be about the same as pre-EPU and expects the ATWS initiator frequency to increase slightly, due to the increases of the initiator frequencies identified above (i.e., more challenges expected due to the overall increase in initiating event frequencies for EPU).

The licensee determined that the above initiating event frequency increases account for about 27% of the overall increase in CDF from EPU. The licensee also performed a number of sensitivity evaluations on the frequency of initiating events that might be affected by EPU. This was achieved by doubling the initiator frequencies for those initiating events that could be impacted by EPU (as discussed above) and evaluating the corresponding increase in CDF. The licensee determined that the most sensitive initiator was the basic reactor trip event (increase in CDF of about 1.2E-6/year), followed by the total loss of the electrical grid (increase in CDF of about 4.9E-7/year).

The NRC staff finds that the licensee's assessment of the impact of the proposed EPU on initiator frequencies seems to be reasonable, and that the change in internal events frequencies is not significant and does not significantly impact CDF. Based on the licensee's evaluations, the staff does not expect the plant to experience a substantial increase in the frequency of initiating events due to EPU that would rebut the presumption of adequate protection provided by the licensee complying with the current regulations. In addition, the staff expects that any significant changes in initiating event frequencies following implementation of the proposed EPU would be identified and tracked under the licensee's existing performance monitoring programs and processes (e.g., Maintenance Rule program) and incorporated into future GPSA model updates.

b. Success Criteria

Success criteria specify the performance requirements on plant systems performing critical safety functions. The licensee performed a review to assess the effect of the increase in thermal power level on success criteria. Safety functions, and related EPU impacts on success criteria considered by the licensee, are discussed in this section.

As a result of the EPU increased boration level, the licensee stated that the MTC would be more negative throughout the EPU fuel cycle as compared to pre-EPU. This improves the likelihood of successful ATWS mitigation. Otherwise, no change to reactivity control success criteria was identified by the licensee. Also, the boron concentration in the reactor water storage tank and the accumulators will be increased. EPU associated conditions reduce the time to reach boron solubility limits in the core for medium and large LOCAs from 20 hours to 6.5 hours. This condition can result in boron precipitation on the fuel assemblies, which reduces heat transfer rates, and may lead to core damage. To preclude this occurrence, the licensee will revise the associated emergency operating procedures to direct the operators to reestablish cold leg injection no later than 6 hours following the termination of safety injection (as opposed to the current direction to reestablish cold leg injection no later than 19 hours). The only potential impact on risk, is from an increase in the probability of the operators failing to reinitiate safety injection within this time period. However, the estimated longest time to reach the crucial procedural step is about 105 minutes into the event. Given that this provides over 4 hours under EPU conditions, there is virtually no change in the human error probability for this action between pre-EPU and EPU.

Due to the increased decay heat during EPU operations, the licensee’s evaluations indicated that two PORVs are required for successful feed-and-bleed (with charging unavailable) as compared to a single PORV for pre-EPU operations. With charging available, one PORV is sufficient for feed-and-bleed, but the time available to initiate feed-and-bleed is reduced. The impact of this change in success criteria is reflected in the overall risk results.

The licensee also indicated that the components required to support at-power RCS and core heat removal using MFW will not change since the condensate booster pumps and MFW pumps are being upgraded. In addition, no changes in the manner of operation or pressure control success criteria were identified.

As a result of the EPU, Ginna is also planning to modify the pressurizer level control program since the level is estimated to have larger variation for EPU (ranging from 20% to 60%), as compared to pre-EPU (ranging from 35% to 50%). Since it is possible that the higher water level could lead to increased PORV challenges and less pressurizer steam volume to react to pressure changes, the licensee investigated this impact within the initiating event frequency analyses by increasing the fraction of reactor trip events due to pressurizer level control problems resulting in a PORV challenge by 50% (from 1.0E-3/year to 1.5E-3/year). The staff expects that any increase in PORV challenges following implementation of the proposed EPU would be identified under the licensee’s performance monitoring programs and processes and incorporated into future GPSA model updates.

The NRC staff finds that the licensee’s assessment of the impact of the proposed EPU on success criteria appears to be reasonable and that there are no issues related to the GPSA success criteria that would rebut the presumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements.

c. Operator Actions and Recovery Actions

Due to the WOG peer review, significant GPSA Revision 5.0 human actions were reassessed using the EPRI HRA calculator for both the pre-EPU and EPU conditions. The licensee examined all human actions in the GPSA to address the impacts associated with adverse environmental conditions and accessibility limitations. In performing the analyses, the licensee divided operator actions into three categories: normal, degraded, or failed. The failure rate for normal operator actions was used for all cases, unless actions were affected by adverse environmental conditions or accessibility limitations. The degraded category used increased rates of failure to account for adverse accident environments and increased dependencies. In the failed category, initiators with either failed fire suppression or a large flood volume were assumed to prevent operators from performing recovery actions and the failure probability for these actions was set to one.

The licensee evaluated operator action response times, failure to recover probabilities, and their associated impacts on CDF, and used these evaluations to develop insights by identifying the significant operator errors and recovery actions impacted by the EPU. Most of the risk impact from human actions at Ginna is related to shutdown operations (see Section 3.e below). The greatest impacts for the Level I GPSA, due to EPU are related to recovery of offsite power and AFW operations. Additional operator action impacts are related to: fire responses (e.g., manually realigning and starting turbine-driven AFW pump), failure to shift to containment sump recirculation, turbine-driven AFW pump operations (e.g., failing to provide lube oil cooling or opening steam valves), failure to open RHR suction/injection valves, failure to implement emergency boration, and failure to align for feed-and-bleed. The licensee determined that the operator action failure probability increases account for about 63% (about 4.8E-6/year) of the overall increase in CDF from EPU due to the impact of reduced response times.

The NRC staff finds that the licensee's HRA and its associated results are reasonable for this application and that there are no issues related to the GPSA HRA that would rebut the presumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements.

d. Component and System Reliability

The licensee indicated that components are modified or replaced to obtain the required performance and operating margins at EPU conditions (e.g., MFW pump modifications). Therefore, the licensee expects plant systems and equipment to continue to operate within design limits. Further, the licensee relies on existing equipment monitoring techniques (e.g., vibration analysis, thermography, oil analysis, and radiography), preventive maintenance, and condition monitoring programs (e.g., maintenance rule and erosion/corrosion) to identify any accelerated component wear that might result from the EPU. Through trending, these programs are expected to identify deviations or potential increases in component failure rates.

For additional assurance of the acceptability of the EPU, the licensee performed sensitivity calculations to evaluate the impact of changes in hardware failure rates. The licensee performed these sensitivity calculations by doubling the likelihood of failure of individual components and evaluating the impact of this change on CDF. Results of these sensitivity evaluations were used to derive several insights regarding plant/operational modifications and improvements that have the potential to reduce risk. Five plant/operational modifications and improvements that showed reductions in the EPU CDF and LERF were identified. Two of these modifications/improvements included:

(1) Modification/procedure change to mechanically limit the open position of selected air-operated hydraulic control valves (HCVs) powered via the inverter and constant voltage transformer. This change enhances the performance of the RHR pumps during shutdown reduced inventory operations.

(2) Modification/procedure change to allow the use of a safety injection pump during a fire scenario to reduce the sensitivity of RCP seal LOCA likelihood during EPU.

The NRC staff finds that the licensee's evaluations of component and system reliability are reasonable, have resulted in identifying opportunities to further improve plant safety, and that there are no issues related to component and system reliability that would rebut the presumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements. The staff expects that the licensee's component monitoring programs, as previously stated, should detect any significant degradation in performance and maintain the current reliability of the equipment.

3. External Events (Level I)

This section addresses the licensee's review of external events, which includes: seismic events, internal fires, and other external events.

a. Seismic Events

The IPEEE program classified Ginna as a focused-scope plant based on the site's seismicity. Ginna performed a seismic margins assessment under the IPEEE program. Safe shutdown success paths were developed to identify systems that must function to successfully shutdown and cool the reactor following the occurrence of an earthquake. All seismic vulnerabilities revealed by the IPEEE program were addressed, with the exception of the vulnerability to flooding from the seismically-induced failure of the reactor makeup water tank (RMWT). It was determined that the failure of this tank could increase the water level in the auxiliary building, flooding the RHR sub-basement area. This vulnerability impacts the plant success path associated with mitigating a small LOCA, since the RHR pumps are required to mitigate a small LOCA. The licensee, in the original submittal, stated that they were committed to performing a cost-benefit analysis of providing seismic qualification of the tank, or otherwise protecting the RHR-related small LOCA mitigation success path. However, since the modification of the RMWT has not been performed, the licensee's seismic risk evaluation performed for EPU considered the RMWT failure and its impacts on plant equipment.

The licensee noted that the increased power level is not expected to affect equipment or structural response during a seismic event. However, a seismic event will likely result in a LOOP without short-term power recovery. This event can be further complicated by the RMWT failure, which the licensee assumed to occur in the event of a seismically-induced non-recoverable LOOP. The licensee's assessment estimated the frequency of a non-recovered LOOP due to a seismic event to be about 1.2E-4/year and the resulting CDF as about 6.4E-6/year (a 0.2% change from pre-EPU to EPU conditions). To assess the importance of the failure of the RMWT, the licensee performed sensitivity calculations pre- and post-EPU assuming the RMWT is failed and then assuming the RMWT is not failed. The estimated increase in CDF for EPU in the case of a non-recoverable LOOP with RMWT failure is approximately 1E-8/year, a very small impact.

To further evaluate the impact of the RMWT seismic failure on plant risk, the staff performed some simplistic risk approximation calculations based on the licensee's seismic margins analysis. The calculations confirmed the licensee's results. The staff also performed some confirmatory calculations using the Standardized Plant Analysis Risk (SPAR) model for Ginna. In the SPAR model, the staff used the licensee's value for a non-recovered LOOP event (1.2E-4/year) to represent the base condition and then added the guaranteed failure of the RMWT and resulting failure of the RHR system to represent the seismic vulnerability condition. The change in CDF between these conditions was estimated to be about 6E-9, representing an increase of about 4%. This is consistent with the licensee's estimated impact.

The NRC staff finds that the licensee's evaluation of the impact of the proposed EPU on seismic risk is reasonable and consistent with the staff's confirmatory evaluations. Thus, the staff finds that there are no issues concerning earthquakes that rebut the presumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements.

b. Fire

The Ginna IPEEE study used both Fire-Induced Vulnerability Evaluation (FIVE) and fire PRA methodologies. FIVE was used for fire area screening and fire PRA was used for evaluation of non-screened areas. In the IPEEE study, fire events were found to be a significant contributor to CDF (approximately 3.3E-5/year). In the GPSA revisions, the internal events PRA model and data were updated and modified to incorporate the fire impacts and to include refined recovery actions, which resulted in changing the CDF to 2.8E-5/year. With EPU, the time available to perform operator actions is decreased as a result of the power increase. The licensee's evaluations showed that the EPU fire CDF increases to approximately 3.1E-5/year, about an 8 percent increase from the pre-EPU CDF. Similarly, the estimated change in LERF increases by about 5%, from 2.8E-6/year to 2.9E-6/year.

The NRC staff finds that the licensee's evaluation of the impact of the proposed EPU on internal fire risk is reasonable and consistent with the staff's expectations gained from previous PWR EPU reviews. Since the CDF risk metrics satisfy the risk acceptance guidelines in RG 1.174, the staff finds that the change in internal fire risk due to the proposed EPU is very small and that there are no issues concerning internal fires that rebut the presumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements.

c. Turbine Missiles

As stated previously, the main generator operating margin is reduced under the EPU conditions. As such, it is expected that there will be a potential increase in the frequency of loss of load events, which will include the rapid closing of the steam admission valves to the turbine to avoid a turbine overspeed, which may also increase the likelihood of a turbine blade ejection. In addition, the increase in operating steam temperature raises the turbine blade operating temperature, which can increase the likelihood of turbine blade crack formation and propagation, and additional stored energy in the turbine high to low pressure stages due to higher steam temperatures may result in higher rotor speeds if the low pressure stop or intercept valve fails to close on a trip. The licensee estimated the change in CDF due to EPU to be approximately 3.2E-7/year (from 9.7E-7/year to 1.3E-6/year).

The NRC staff finds that the licensee's analyses are reasonable and that there are no issues concerning turbine missiles that rebut the presumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements.

d. Other External Events

The IPEEE study found no high wind, external floods, or offsite industrial facility accidents that significantly altered the estimates of either CDF or LERF. The licensee updated their IPEEE data and concluded that no other external events can affect applicable protective features, such as missile or flood barriers. However, similar to other external events (e.g., seismic events), these events may result in a LOOP where short-term power recovery is unlikely. The impact of EPU from these other external events, due to an unrecovered LOOP, was evaluated in a sensitivity calculation assuming these events increased the LOOP initiating event frequency. From this sensitivity calculation, the licensee determined the impact of these other external vents as being insignificant, with an increase in CDF estimated to be about 1.2E-9/year, an increase of 0.3% from pre-EPU to EPU.

The staff finds that the licensee's evaluation of the impact of the proposed EPU on risk from these other external events is reasonable and that there are no issues concerning these other external events that rebut the presumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements.

e. Shutdown Operation Risk

Under EPU conditions, decay heat levels are higher and, subsequently, cooldown times are increased. However, the licensee's design analysis indicates that the requirements associated with achieving cold shutdown (200 EF) can be met.

During an outage, the licensee stated that shutdown safety parameters, including decay heat removal, vital power, reactivity control, containment closure, and the RCS, are closely monitored. No EPU changes are anticipated to affect the primary system, instrumentation for reduced inventory operation, or equipment and methods used for mitigation of loss of RHR cooling. In addition, existing reduced inventory procedures and administrative controls are structured by the licensee to minimize the likelihood of core uncovery while ensuring a defense-in-depth response is available, if needed.

Shutdown-related initiating events are: loss of RHR, boron dilution, LOCA, and RCS over-pressurization. The power uprate does not increase the frequency of these initiators. However, the increase in temperature and increase in decay heat will decrease the time available for operator actions. To address this impact of EPU, the licensee evaluated the operator failure likelihood based on the shorter times available. As expected, the most significant change was found to be failure to recover from loss of shutdown cooling before onset of boiling. This impact occurs during reduced inventory, early in shutdown, when there is a small time window available for recovery. The GPSA quantification results indicated an increase in shutdown CDF of about 21% (from 1.1E-5/year to 1.3E-5/year), while the change in LERF was about 17% (from 3.5E-7/year to 4.0E-7/year).

In addition, the NRC evaluated the impact of the RMWT seismic vulnerability, since the RHR system may be failed by this event. The staff performed a simplistic calculation based on the licensee's value for a seismically-induced non-recovered LOOP event (1.2E-4/year) that occurs during shutdown operations. In this scenario, the seismic event is assumed to fail the RMWT, which consequentially fails the RHR system. Due to the low frequency of occurrence of this event (about 5E-6/year) and the fact that the critical time period (in which recovery actions are limited) would be a short duration early in shutdown (i.e., during reduced inventory operations), the risk from seismic events during shutdown operations is considered small.

The staff finds that the licensee's assessment of shutdown risks associated with the proposed EPU is reasonable and that there are no issues concerning shutdown operations that rebut the assumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements.

5. LERF Analysis (Level II)

The licensee used a simplified containment event tree to evaluated LERF (i.e., following NUREG/CR-6595 for PWRs with a large dry containment). As expected, SGTRs and interfacing system LOCAs were identified as the most significant contributors to LERF. The licensee's evaluations also showed the EPU LERF to be about 5.4E-6/year, an increase of about 10% from the pre-EPU value of about 4.9E-6/year. This increase is dominated by the internal events and fire contributions previously discussed.

The NRC staff finds that there are no issues concerning the licensee's LERF analysis that would rebut the presumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements.

<u>Conclusion</u>

The licensee evaluated the risk impact associated with the EPU, with a total CDF of 7.1E-5/year (12% increase) and a total LERF of 5.4E-6/year (10% increase), and determined the risk increase is small and within the acceptance guidelines of RG 1.174. Further, the licensee used the EPU GPSA to gain insights, with regard to plant modifications and operational improvements, that could reduce risk. The licensee identified five potential changes that are both risk and cost beneficial and made the observation that the risk reduction associated with the first three items would likely completely offset the risk increase associated with the EPU. The identified modification/procedure changes are:

(1) Optimize use of the safety injection pumps during fires

(2) Mechanically limit RHR HCVs from failing completely open,

(3) Provide backup air supply to the charging pumps,

(4) Relocate charging pump control power disconnect, and

(5) Install local controls for the turbine-driven AFW pump discharge motor-operated valve.

The NRC staff has reviewed the licensee's assessment of the risk implications associated with the implementation of the proposed EPU and concludes that the licensee has adequately modeled and/or addressed the potential impacts associated with the implementation of the proposed EPU. In addition, the staff expects that any significant changes in plant performance following implementation of the proposed EPU would be identified and tracked under the licensee's existing performance monitoring programs and processes and incorporated into future GPSA model updates. The NRC staff further concludes that the results of the licensee's risk analysis indicate that the risks associated with the proposed EPU are acceptable and do not create the "special circumstances" described in Appendix D of SRP Chapter 19. Therefore, the NRC staff finds the risk implications of the proposed EPU acceptable.

3.0 FACILITY OPERATING LICENSE AND TS CHANGES

To achieve the EPU, the licensee proposed the following changes to the Facility Operating License and TSs for Ginna.

3.1 Operating License change:

License condition 2.C.1. Maximum Power Level.

The licensee proposed to change the maximum core power level from 1520 MWt to 1775 MWt.

3.2 TS changes:

Some changes are required for the EPU and others are requested improvements that are not required to support facility operation under EPU conditions but provide additional margin with respect to the EPU.

a. TS 1.1, "Definitions," Rated Thermal Power

The licensee proposed to change the RTP from 1520 MWt to 1775 MWt. The change reflects the actual value in the proposed application and is consistent with the results of the licensee's supporting safety analyses. The NRC staff, therefore, finds this proposed change acceptable.

b. TS 3.3.1, "Reactor Trip System," LCO Actions, Condition O

The licensee proposed to reduce the required thermal power value from < 50% RTP to < 30% RTP. The licensee stated that the analyses performed for the EPU conditions determined that an analytical limit of 35% power is required to ensure all accidents and transients impacted by RCS flow maintain DNB within acceptable limits (Reference Sections 2.4.1 and 2.8.5.3.1 of the licensing report). The value specified in the Actions Condition is based on the Reactor Trip System Interlocks - Power Range Neutron Flux, P-8 Limiting Safety System Setting (LSSS).

The NRC finds that the required thermal power value associated with a single loop loss of coolant flow trip is reduced from –50% RTP to –30% RTP. The value specified in the Action Condition is based on the Reactor Trip System Interlocks -

Power Range Neutron Flux, P-8 limiting safety system setting (LSSS), which has been determined to be –29%. The calculation of LSSS has been performed consistent with the staff approved performance based setpoint methodology and therefore, the NRC staff finds the proposed change acceptable.

c. TS Table 3.3.1-1, "Reactor Trip System," Functional 2.a

The licensee proposed to reduce the Power Range Neutron Flux - High Limiting Safety System Setting from # 112.27% RTP to # 109.27% RTP.

EPU redefines the 100% power neutron flux levels and will impact the flux level to% power relationship for the Power Range nuclear instruments. The EPU accident and transient analyses determined that for some accidents the AL for the Power Range high power trip would need to be reduced from the current 118% to 115%, which will reduce the LSSS value from #112.27% RTP to #109.27% RTP (Reference Attachment 5 Section 2.4.1, 2.8.5.4.1, and 2.8.5.4.6). The calculation of the LSSS has been performed consistent with the performance based methodology approved by Amendment 85 to the Ginna TSs (Reference 7.4).

The NRC staff finds that the calculation of the LSSS has been performed consistent with the NRC staff approved performance based setpoint methodology. Therefore, the staff finds the proposed change acceptable.

d. TS Table 3.3.1-1, Functional 16.c

The licensee proposed to reduce the Reactor Trip System Interlocks - Power Range Neutron Flux, P-8 Limiting Safety System Setting from # 49.0% RTP to # 29.0% RTP.

The analyses performed for EPU determined that an analytical limit of s 35% power is required to ensure all accidents and transients impacted by RCS flow maintain DNB within acceptable limits. Therefore, the P-8 TS LSSS limit associated with a single loop loss of coolant flow trip will be reduced from the current # 49.0% power to # 29.0% (Reference Attachment 5 Section 2.4.1 and 2.8.5.3.1). The calculation of the LSSS has been performed consistent with the performance based methodology approved by Amendment 85 to the Ginna TSs (Reference 7.4).

The NRC staff finds that the calculation of the LSSS has been performed consistent with NRC staff approved performance based setpoint methodology. Therefore, the staff finds the proposed change acceptable.

e. TS Table 3.3.1-1, Footnote (h)

The licensee proposed to reduce the referenced thermal power value from $ 50% RTP to $30% RTP.

The analyses performed for EPU determined that a lower power level is required to ensure all accidents and transients impacted by RCS flow maintain DNB within acceptable limits (Reference Attachment 5 Section 2.4.1 and 2.8.5.3.1). The value specified in the Applicability footnote is based on the Reactor Trip System Interlocks - Power Range Neutron Flux, P-8 LSSS associated with a single loop loss of coolant flow trip.

Since this footnote is based on the LSSS determined with the NRC staff approved performance based setpoint methodology, the NRC staff finds the proposed change acceptable.

f. TS Table 3.3.2-1, "ESFAS Instrumentation," Functional 1.d

The licensee proposed to reduce the Safety Injection Pressurizer Pressure-Low Limiting Safety System Setting from $ 1744.8 psig to $ 1729.8 psig. This is a margin improvement related change.

In order to increase the calibration margin on ESFAS parameter related setpoints, the AL used in the accident and transient analyses was changed from 1715 psig to 1700 psig. Since acceptable results were achieved using this value, the value will become the basis for establishing the TS LSSS value and field setpoints (Reference Attachment 5 Section 2.4.1,2.8.5.1.1, 2.8.5.6.2, and 2.8.5.6.3). The calculation of the LSSS has been performed consistent with the performance based methodology approved by Amendment 85 to the Ginna TSs (Reference 7.4).

Since this LSSS value was based on the NRC staff approved performance based setpoint methodology, the NRC staff finds the proposed change acceptable.

g. TS Table 3.3.2-1, Functional 2.c

The licensee proposed to increase the Containment Spray Containment Pressure-High High Limiting Safety System Setting from # 31.11 psig to # 32.11 psig (narrow range) and from #28.6 psig to # 29.6 psig (wide range). This is a margin improvement related change.

In order to increase the calibration margin on ESFAS parameter related setpoints, the analytical value used in the accident and transient analyses was changed from 32.5 psig to 33.5 psig. Since acceptable results were achieved using this value, the value will become the basis for establishing the TS LSSS value and field setpoints (Reference Attachment 5 Section 2.4.1 and 2.6.1). The calculation of the LSSS has been performed consistent with the performance based methodology approved by Amendment 85 to the Ginna TSs (Reference Section 7.4 of the licensing report).

Since this LSSS value is based on the NRC staff approved performance-based setpoint methodology, the NRC staff finds the proposed change acceptable.

h. TS Table 3.3.2-1, Functional 4.d

The licensee proposed to increase the Steam Line Isolation High Steam Flow Limiting Safety System Setting from # 0.42E6 lbm/hr at 1005 psig to # 1.30E6 lbm/hr at 1005 psig. This is an EPU and margin improvement related change.

The AL for the High Steam Flow input to Containment Main Steam Line Isolation is being changed to allow additional instrumentation calibration margin. The AL will be changed from the current 0.66x10E6 lbm/hr @ 1005 psig to 1.50x10E6 lbm/hr @ 1005 psig. Since acceptable results were achieved using this value, the value will become the basis for establishing the TS LSSS value and field setpoints (Reference Attachment 5 Section 2.4.1 and 2.8.5.1.2). The calculation of the LSSS has been performed consistent with the performance based methodology approved by Amendment No. 85 to the Ginna TSs (Reference Section 7.4 of the licensing report).

Since this LSSS value is based on the NRC approved performance based setpoint methodology, the NRC staff finds the proposed change acceptable.

i. TS Table 3.3.2-1, Functional 4.d

The licensee proposed to decrease the Steam Line Isolation Coincident with Tavg-Low Limiting Safety System Setting from $ 544.98 EF to $ 544.0 EF. This is a margin improvement related change.

In order to increase the calibration margin on ESFAS parameter related setpoints, the AL used in the accident and transient analyses was changed from 543 EF to 530 EF. Since acceptable results were achieved using this value, the value will become the basis for establishing the TS LSSS value and field setpoints (Reference Attachment 5 Section 2.4.1 and 2.8.5.1.2). The calculation of the LSSS has been performed consistent with the performance based methodology approved by Amendment No. 85 to the Ginna TSs.

Since this LSSS value is based on NRC-approved performance based setpoint methodology, the NRC staff finds the proposed change acceptable.

k. TS Table 3.3.2-1, Functional 4.e

The licensee proposed to increase the Steam Line Isolation High-High Steam Flow Limiting Safety System Setting from # 3.63E6 lbm/hr at 755 psig to # 4.53E6 lbm/hr at 785 psig. This is an EPU and margin improvement related change.

EPU redefines the high-high steam line flow AL as #155% nominal flow (5.96E6 lbm/hr). This change in assumed steam flow resulted in an increase in the TS LSSS accordingly (Reference Attachment 5 Section 2.4.1 and 2.8.5.1.2). The calculation of the LSSS has been performed consistent with the performance based methodology approved by Amendment No. 85 to the Ginna TSs.

Since this value is based on the NRC-approved performance based setpoint methodology, the NRC staff finds the proposed change acceptable.

l. LCO for TS 3.4.10, "Pressurizer Safety Valves"

The licensee proposed to decrease the upper lift setting for the pressurizer safety valves from # 2544 psig to # 2542 psig.

A total pressurizer safety valve setpoint tolerance of -3%/+2.3% was supported in the loss of load analysis described in the licensing report (Section 2.8.5.2.1). For the DNBR case and main steam system peak pressure case, the negative tolerance was applied to conservatively reduce the setpoint. For the case analyzed for peak RCS pressure, the positive tolerance was applied to conservatively increase the setpoint pressure. Since the pressurizer safety valve lift setting and tolerances are consistent with the assumptions in the analyses, the staff finds the change acceptable.

m. LCO for 3.7.6, "Condensate Storage Tanks (CSTs)"

In SR 3.7.6.1, the licensee proposed to increase the required volume listed for the CSTs from $ 22,500 gallons to $ 24,350 gallons.

Two condensate storage tanks are used as a source of water for AFW operation, each of which will be able to provide the TS minimum required usable volume. This minimum useable volume for EPU operation is an inventory of 24,350 gallons to meet the plant licensing basis of decay heat removal for 2 hours after a reactor trip from full power as described in the EPU licensing report Section 2.5.4.5. Therefore, the NRC staff finds the change acceptable.

3.3 Licensing Basis Changes

Control Room Dose Increase

The dose analysis for the EPU indicates that the control room dose for the LOCA increased from 3.51 REM TEDE to 4.6 REM TEDE, and the Rod Ejection Accident (REA) control room dose increased from 1.19 REM TEDE to 1.83 REM TEDE. These increases are above the threshold for minimal increase under 10 CFR Part 50.59 and will require NRC review and approval.

The dose analysis for the EPU indicates that the control room dose for the LOCA increased from 3.51 REM TEDE to 4.6 REM TEDE, and the REA control room dose increased from 1.19 REM TEDE to 1.83 REM TEDE. These increases are above the threshold for minimal increase under 10 CFR Part 50.59 and will require NRC review and approval. The Dose Analysis for the EPU is summarized in EPU licensing report Section 2.9.2, "Radiological Consequences Analyses Using Alternative Source Terms." An increase in licensed power results in an increase in source term and, therefore, projected dose is expected to increase. The licensee has calculated the dose for all of the DBAs required by RG 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors," and SRP Section 15.0.1, "Radiological Consequence Analyses Using Alternative Source Terms." Doses were calculated for Exclusion Area Boundary (EAB), Low Population Zone, and Control Room for each accident. For all of the doses calculated, only the REA and LOCA control room dose exceeded the 10% minimal increase criteria. However, these doses are considered acceptable because they remain less than the limits established in 10 CFR 50.67, “Accident source term,” and the acceptance criteria contained in RG 1.183 and SRP 15.0.1.

The NRC staff evaluated the licensee’s revised analyses of control room dose for all DBAs, including the LOCA and the REA, as described in Section 2.9.2 of this SE. The NRC staff found that the licensee has used analysis methods, inputs and assumptions consistent with applicable regulatory guidance in RG 1.183. The NRC staff also concluded that the licensee has adequately accounted for the effects of the proposed EPU in its revised DBA dose analyses, and that the proposed EPU is acceptable with respect to the radiological consequences of DBAs.

4.0 REGULATORY COMMITMENTS

The licensee has made the following regulatory commitments, which will be completed prior to restart from the fall 2006 refueling outage:

1. Update flow-accelerated/erosion-corrosion program to account for higher EPU flowrates. (licensing report Section 2.1.8)

2. Modify fatigue monitoring program to incorporate EPU conditions. (licensing report Section 2.2.2).

3. Modify inservice inspection and inservice testing programs to account for new SSCs and conditions. (licensing report Sections 2.2.4 and 2.5.5.1)

4. Implement modifications and procedure changes to incorporate App. R mitigation strategies. (licensing report Section 2.5.1.4)

5. Revise environmental qualification files to document modified EQ parameters. Include continuation of local temperature monitoring program in containment for qualified life assessments. Resolve the impact of localized containment fan cooler HEPA filter dose. (licensing report Section 2.3.1)

6. Provide training (especially for operator timeline changes) and make procedure changes as needed to account for higher decay heat levels, especially as related to RHR, CCW, SFPC, AFW, SW systems. (licensing report Sections 2.8.7.3 and 2.11)

7. Provide simulator changes and training to account for increased power level and resultant plant changes. (licensing report Section 2.11)

8. Modify licensing basis for SWS train operability from 1 to 2 pumps. (licensing report Section 2.5.4)

9. Implement risk-beneficial modifications to Charging, SI, and RHR systems. (licensing report Section 2.13)

10. Modify control and indication setpoints as needed for operation at EPU conditions. (licensing report Sections 2.4.2, 2.8.4.1, and 2.8.5)

11. Maintain vibration monitoring program during power ascension testing. (licensing report Section 2.5.5.1)

12. Submit proposed change to TS 4.3.3 that would revise the number of fuel assemblies that are allowed to be stored in the SFP to 1321 prior to startup for EPU operation. (licensing report Section 2.5.4.1)

The NRC staff finds that reasonable controls for the implementation and for subsequent evaluation of proposed changes pertaining to the above regulatory commitments are best provided by the licensee’s administrative processes, including its commitment management program. The above regulatory commitments do not warrant the creation of regulatory requirements (items requiring prior NRC approval of subsequent changes).

5.0 RECOMMENDED AREAS FOR INSPECTION

As described above, the NRC staff has conducted an extensive review of the licensee's plans and analyses related to the proposed EPU and concluded that they are acceptable. The NRC staff’s review has identified the following areas for consideration by the NRC inspection staff during the licensee's implementation of the proposed EPU. On the basis of this review, the NRC staff has identified the following areas for consideration by its inspection staff during the licensee’s implementation of the proposed EPU. These areas recommended are:

1. Actions associated with the licensee’s commitments as described in Section 4.0 of this SE.

2. As described in SE Sections 2.4, 2.5.1.2.2, and 2.12, the mechanical overspeed trip setting of the main turbine will be modified slightly by the EPU, and the overspeed trip device as well as the turbine stop, control, and intercept valves are relied upon to assure that the turbine is properly controlled and will not overspeed during EPU operation, creating undue challenges to reactor safety systems and increasing the potential for generating turbine missiles. The licensee plans to perform a mechanical overspeed trip test of the main turbine at 20% power, and turbine stop, control, and intercept valve testing will be performed at 50% power to confirm proper performance. The confirmation of acceptable performance of the mechanical overspeed trip device, and turbine stop, control, and intercept valves, are recommended for inspection.

3. As discussed in SE Section 2.5.5.3, the turbine bypass valves are relied upon in the accident analyses and changes to the control settings are being made to accommodate EPU. The licensee indicated that performance of the steam dump system will be verified during transient tests. The confirmation of the acceptable performance of the turbine bypass valves are recommended for inspection.

4. As discussed in SE Section 2.5.4.5, the SAFW system is credited for mitigating Appendix R scenarios and certain HELBs. The required flow rate will increase from 200 to 235 gpm for EPU operation (with SGs at maximum pressure), and modifications to the control valve trim are necessary to achieve this flow rate. The licensee plans to verify that the SAFW

system will deliver the required flow during power ascension testing prior to exceeding 1520 MWt. The confirmation of the acceptable performance of the SAFW system is recommended for inspection.

5. As described in SE Section 2.5.5.4, the performance of the condensate and feedwater system (CFS) is relied upon to minimize undue challenges to safety systems. In order to accommodate the higher flow requirements for EPU operation, CFS modifications and changes to control settings are required. The licensee will confirm proper performance of the CFS during power ascension and transient testing. NRC inspection to confirm acceptable performance of the CFS (consistent with model predictions) should be included among the items that are being considered for inspection, with particular attention placed on performance of the CFS following any inadvertent loss of a condensate pump, condensate booster pump, feedwater pump, or feedwater heater drain pump.

6. As described in licensing report Section 2.2.2.2.2, "Balance-of-Plant Piping, Components, and Supports, " nine supports will be upgraded and one support will be added to the main steam system due to potentially larger EPU steam hammer loads resulting from a turbine stop valve closure event. A sample of the plant modification packages for these supports should be considered for inspection. This should include a check of the one support that is being upgraded in the main feedwater system.

7. As discussed in SE Section 2.2.2, the implementation of the licensee's vibration monitoring program should be considered for inspection as the licensee proceeds through the steps to full EPU. In this regard, it is recommended that the following areas be considered:

   a. MFIV actuator replacement and qualification.

   b. Determination of SSCs to be monitored for increased vibration.

   c. Licensee's monitoring of SSC vibration and assessment during EPU operation.

8. The conduct of the licensee's surveys and evaluation of the post-EPU dose rates should be considered for inspection. The licensee stated that it would perform post-EPU dose rate surveys of affected areas of the containment, auxiliary building, and intermediate building to detect any abnormal readings. In addition, the licensee also was to perform a radiation survey in containment during the first at power entry following the EPU to evaluate any changes in containment dose rates from pre-EPU at power survey data. Since the licensee has committed to perform these post-EPU radiation surveys to determine the effect of the EPU on dose rates (licensee estimated that dose rates would increase in proportion to the power uprate percent increase in power), the verification that the licensee performance of these post-EPU radiation surveys as committed is recommended for inspection.

9. On August 20, 1974, a PORV failed open at the Beznau plant (2-loop Westinghouse) in Switzerland because of a mechanical failure in the valve stem. Ginna was equipped with the same design (and material) PORVs. It is recommended that the licensee's evaluation of the experience of the PORV valve stems be evaluated for inspection. (See also

Amendment No. 27, in which Ginna removed the pressurizer level coincidence logic with pressurizer pressure (TMI action response to IE 79-06A)).

10. As discussed in SE Section 2.1.8 and licensing report Section 2.1.8, the licensee concluded that changes due to the power uprate will increase the potential for and rate of flow accelerated corrosion (FAC) of some components. The licensee stated that it is currently updating all of the Ginna FAC models to incorporate the uprate conditions and has added components to the FAC program based on changes in operating conditions. The licensee will also evaluate EPU-related plant modifications for inclusion in the program. Completion and implementation of the FAC model update with the additional components and EPU-related plant modifications, as appropriate, is recommended for inspection.

11. As described in SE Section 2.11, Operator Training is being conducted related to the EPU. With the inclusion of revised procedures and updated simulator to reflect the plant modifications made at Ginna for the purpose of the EPU, it is recommended that operator training in accordance to the licensee's commitments be considered for inspection. This area should review the actions taken to validate any operator actions times that will be affected by the EPU.

12. In Paragraph 02.01.d. of NRC Inspection Procedure 71004, it states that the inspector should review the testing portion of the approved license amendment or the NRC SE and select major tests to be monitored and evaluated. In this regard, the following areas should be considered for inspection:

    a. Monitor the licensee's proposed two transient tests. The first transient test that the licensee will perform is a 10% load ramp test, both down and up at 1% per minute, at 30% and 100 EPU power. This test will result in a ramp change in the pressurizer program level as a result of the change in reactor power and coolant temperature. This, the licensee's verification that the actual program pressurizer level tracks as expected with the changes to program pressurizer level is recommended for inspection.

    b. The second transient test that the licensee stated that will be performed to verify the performance of the pressurizer level control system is a manual turbine trip from approximately 30% power. This test will cause a rapid change in program level as a result of a rapid change in reactor power from approximately 30% to 10%. Thus, the licensee's verification that the actual pressurizer level response matches the results with the expected change in program level is recommended for inspection. Additionally, the acceptance criteria for the overall integrated plant response is as predicted.

6.0 STATE CONSULTATION

In accordance with the Commission's regulations, the New York State official was notified of the proposed issuance of the amendment. The State official had no comments.

7.0 ENVIRONMENTAL CONSIDERATION

Pursuant to 10 CFR Part 51.21, 51.32, 51.33, and 51.35, a draft Environmental Assessment and finding of no significant impact was prepared and published in the *Federal Register* on April 12, 2006 (71 FR 18779). The draft Environmental Assessment provided a 30-day opportunity for public comment. The NRC staff received comments, which were addressed in the final environmental assessment, from the Division of Environmental Permits, Region 8, New York State Department of Environmental Conservation. The final Environmental Assessment was published in the *Federal Register* on June 30, 2006 (71 FR 37614). Accordingly, based upon the environmental assessment, the Commission has determined that the issuance of this amendment will not have a significant effect on the quality of the human environment.

8.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public.

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Attachment: List of Acronyms

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LIST OF ACRONYMS

AAC	alternate ac sources
ac	alternating current
ADFCS	advanced digital feedwater control system
AFD	axial flux differential
AFW	auxiliary feedwater
AL	analytical limit
ALARA	as low as reasonably achievable
AMSAC	Anticipated-transient-without-scram mitigation system actuation circuitry
ANS	American Nuclear Society
ANSI	American National Standards Institute
AOO	abnormal operating occurence
ARAVS	auxiliary and radwaste area ventilation system
ARI	alternate rod insertion
ART	adjusted reference temperature
ARV	atmospheric relief valve
ASME	American Society of Mechanical Engineers
ATWS	anticipated transient without scram
B&PV	boiler and pressure vessel
B&W	Babcock and Wilcox
BE	best estimate
BL	bulletin
BLPB	branch line pipe break
BMI	bottom mounted instrument
BOP	balance-of-plant
BRS	boron recovery system
BSS	borated stainless steel
BTP	branch technical position
BWC	B&W Canada

CAP	corrective action process
CASS	cast austenitic stainless steel
CCW	component cooling water
CCWS	component cooling water system
CDF	core damage frequency
CE	Combustion Engineering
CFR	*Code of Federal Regulations*
CHF	critical heat flux
CRCFS	containment recirculation cooling and filtration system
CFS	condensate and feedwater system
COLR	core operating limits report
CRAVS	control room area ventilation system
CRFC	containment recirculation fan cooler
CRDM	control rod drive mechanism
CRAVS	control room area ventilation system
CRDS	control rod drive system
CREATS	control room emergency air treatment system
CREZ	control room emergency zone
CRHVAC	control room heating, ventilating, and air conditioning system
CS	containment spray
CSS	containment spray system
CUF	cumulative fatigue usage factor
CVCS	chemical and volume control system
CWS	circulating water system
DBA	design-basis accident
DBLOCA	design-basis loss-of-coolant accident
dc	direct current

DG	draft guide
DNB	departure from nucleate boiling
DNBR	departure from nucleate boiling ratio
DSS	diverse scram system
EAB	exclusion area boundary
E/C	erosion-corrosion
ECCS	emergency core cooling system
ECT	eddy-current testing
EDG	emergency diesel generator
EFDS	equipment and floor drainage system
EFPD	effective full-power day
EFPY	effective full-power year
EHC	electro-hydraulic control
EMA	equivalent margin analysis
EOL	end of life
EPG	emergency procedure guideline
EPRI	Electric Power Research Institute
EPU	extended power uprate
EQ	environmental qualification
ERG	emergency response guideline
ESF	engineered safety feature
ESFAS	engineered safety feature actuation system
ESFVS	engineered safety feature ventilation system
FAC	flow-accelerated corrosion
FACTS	fuel assembly compatibility test system
FCEP	fuel criteria evaluation process
FHA	fuel-handling accident
FIV	flow-induced vibration

FLB	feedwater line break
FPP	fire protection program
FR	functional restoration procedure
FW	feedwater
GDC	general design criterion (or criteria)
GL	generic letter
GPM	gallons per minute
GWMS	gaseous wate management system
HELB	high-energy line break
HFP	hot full power
HHSI	high-head safety injection
HX	heat exchanger
HZP	hot zero power
I&C	instrumentation and controls
IASCC	irradiation-assisted stress-corrosion cracking
IFM	intermediate flow mixing
IGSCC	intergrannular stress corrosion cracking
IN	information notice
IPE	individual plant examination
IPEEE	individual plant examination of external events
ISI	inservice inspection
LAR	license amendment request
LBB	leak-before-break
LBLOCA	large-breal loss-of-coolant accident
LERF	large early release frequency
LLHS	light load handling system
LOCA	loss-of-coolant accident
LONF	loss of normal flow

LOOP	loss of offsite power
LPZ	low population zone
LRA	locked rotor accident
LTOP	low temperature operation
LWMS	liquid waste management system
MC	main condenser
MCES	main condenser evacuation system
MCLB	main coolant loop pipe break
MEPC	moderate energy pipe crack
MFBPV	main feedwater bypass valve
MFPDV	main feedwater discharge valve
MFIV	main feedwater isolation valve
MFRV	main feedwater regulating valve
MOV	motor-operated valve
MRP	materials review program
MRPI	microprocessor rod position intrumentation
MSL	main steamline
MSIV	main steam isolation valve
MSLB	main steamline break
MSR	moisture separator reheater
MSSS	main steam supply system
MSSV	main steam safety valve
MTC	moderator temperature coefficient
MURP	measurement uncertainty recapture power
MWt	megawatts thermal
NEI	Nuclear Energy Institute
NPSH	net positive suction head
NRC	Nuclear Regulatory Commission

NRR	Office of Nuclear Reactor Regulation
NRS	narrow range span
NSSS	nuclear steam supply system
NYISO	New York Independent System Operator
O&M	operations and maintenance
OBE	operating basis earthquake
OFA	optimized fuel assembly
OPC	overspeed protection controller
P-T	pressure-temperature
PCT	peak clad temperature
PMT	post-modification test
PRA	probablistic risk assessment
PRT	pressurizer relief tank
PTLR	pressure-temperature limits report
PTS	pressurized thermal shock
PWR	pressurized-water reactor
PWSCC	primary water stress-corrosion cracking
RAI	request for additional information
RAOC	relaxed axial offset control
RCCA	rod cluster control assembly
RCL	reactor coolant loop
RCP	reactor coolant pump
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
PPCS	plant process computer system
REA	rod ejection accident
RG	regulatory guide
RHR	residual heat removal

RIA	reactivity insertion accident
RMWT	reactor makeup water tank
RPS	reactor protection system
RS	review standard
RSG	replacement steam generator
RTDP	revised thermal design procedure
RTE	random turbulence excitation
RTP	rated thermal power
RV	reactor vessel
RVCH	reactor vessel closure head
RWAP	rod worth at power
RWFSC	rod withdrawal from subcritical condition
RWST	refueling water storage tank
SAFDL	specified acceptable fuel design limit
SAFW	standby auxiliary feedwater
SAG	severe accident guideline
SAL	safety analysis limit
SAMG	severe accident mitigation guidelines
SAR	Safety Analysis Report
SAT	systematic approach to training
SBLOCA	small-break loss-of-coolant accident
SBO	station blackout
SCC	stress-corrosion cracking
SDM	shutdown margin
SE	safety evaluation
SEP	systematic evaluation program
SFP	spent fuel pool
SFPAVS	spent fuel pool area ventilation system

SG	steam generator
SGBS	steam generator blowdown system
SGTR	steam generator tube rupture
SI	safety injection
SIPE	significant infrequently performed evolution
SPDS	safety parameter display system
SRP	Standard Review Plan
SSCs	structures, systems, and components
SSE	safe-shutdown earthquake
STDP	standard thermal design procedure
SWMS	solid waste management system
SWS	service water system
SWSROP	service water system reliability optimization program
TAVS	turbine area ventilation system
TBS	turbine bypass system
TCV	turbine control valve
TDAFW	turbine-driven auxiliary feedwater
TDF	thermal design flow
TEDE	total effective dose equivalent
TGSCC	transgrannular stress corrosion cracking
TGSS	turbine generator sealing system
TLAA	time limited aging analyses
TMA	tornado missile accident
T-H	thermal-hydraulic
TRM	technical requirements manual
TS	technical specification
TSTF	technical specification task force
UFSAR	updated final safety analysis report

UHS	ultimate heat sink
UPI	upper plenum injection
USE	upper shelf energy
UT	ultrasonic testing
VFTP	ventilation filter testing program
VS	vortex shedding
WOG	Westinghouse Owners Group