Table of Contents

Safety Evaluation Related to Extended Power Uprate at

Susquehanna Steam Electric Station, Units 1 and 2

Enclosure

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 246 TO FACILITY OPERATING LICENSE NO. NPF-14

AND AMENDMENT NO. 224 TO FACILITY OPERATING LICENSE NO. NPF-22

PPL SUSQUEHANNA, LLC

ALLEGHENY ELECTRIC COOPERATIVE, INC.

SUSQUEHANNA STEAM ELECTRIC STATION, UNITS 1 AND 2

DOCKET NOS. 50-387 AND 50-388

1.0 INTRODUCTION

1.1 Application

By license amendment request (LAR) dated October 11, 2006 (Agencywide Documents Access and Management System (ADAMS) Accession Nos. ML062900160, ML062900161, ML062900162, ML062900306, and ML062900401), PPL Susquehanna, LLC (PPL, the licensee) requested changes to the Facility Operating Licenses and Technical Specifications (TSs) for Susquehanna Steam Electric Station (SSES) Units 1 and 2. Supplementing this request were letters dated October 25, December 4 and 26, 2006, February 13, March 14 and 22, April 13, 17, 23, 26, and 27, May 3, 9, 14, and 21, June 1, 4, 8, 14, 20, and 27, July 6, 12, 13, 30, and 31, August 3, 13, 15, and 28, September 19, October 5, November 30, December 10, 2007, and January 9, 24, and 29, 2008 (ADAMS Accession Nos., ML063120119, ML063460354, ML070040376, ML070610371, ML070860229, ML070890411, ML071150113, ML071150043, ML071240196, ML071280506, ML071300265, ML071360026, ML071360036, ML071360041, ML071420064, ML071420047, ML071500058, ML071500300, ML071620218, ML071620311, ML071620299, ML071620342, ML071620256, ML071700096, ML071700104, ML071710442, ML071780627, ML071860142, ML071860421, ML071870449, ML072010337, ML072010019, ML072060604, ML072200101, ML072220477, ML072220482, ML072220485, ML072220490, ML072280247, ML072340597, ML072340603, ML072480182, ML072820283, ML072900642, ML073450822, ML073620458, and ML080230542, respectively). The supplemental letters dated October 25, December 4 and 26, 2006, February 13, March 14 and 22, April 13, 17, 23, 26, and 27, May 3, 9, 14, and 21, June 1, 4, 8, 14, 20, and 27, July 6, 12, 13, 30, and 31, and August 3, 13, and 15, and 28, September 19, October 5, November 30, December 10, 2007, and January 9, 24, and 29, 2008, provided additional clarifying information that did not expand the scope of the initial application as published in the *Federal Register* on March 13, 2007 (72 FR 11392).

The proposed amendment would increase the maximum steady-state reactor core power level from 3489 megawatts thermal (MWt) to 3952 MWt, which is an increase in thermal power of approximately 13 percent. The proposed increase in power level is considered an extended power uprate (EPU).

1.2 Background

1.2.1 General Design Features

SSES Units 1 and 2 are boiling-water reactor (BWR) plants of the BWR/4 design with a Mark-II containment. The U.S. Nuclear Regulatory Commission (NRC or the Commission) licensed SSES Units 1 and 2 on November 12, 1982, and June 27, 1984, respectively, for full-power operation at 3293 MWt.

The SSES Unit 1 and 2 site encompasses approximately 2355 acres located on the west bank of the Susquehanna River in Salem Township, Luzerne County, Pennsylvania, with additional recreational and agricultural lands located on the east bank of the rivers in Conyngham and Hollenback Townships. The site is 4 miles south of Shickshinny, 5 miles northeast of Berwick, 50 miles northwest of Allentown, and 70 miles northeast of Harrisburg. The distance of the low-population zone is a 3-mile radius from the center of the exclusion area. The nearest population center as defined in Title 10, Part 100, “Reactor Site Criteria,” of the *Code of Federal Regulations* (10 CFR Part 100), is the City of Wilkes-Barre, located about 21 miles to the northeast.

PPL has performed two power uprates. The first power uprate, termed a “stretch uprate,” increased the licensed thermal power by approximately 4.5 percent. The second power uprate of 1.4 percent resulted from improved instrumentation, which allowed a reduction in the uncertainty in thermal power; this is termed an “Appendix K uprate” or measurement uncertainty recapture.

1.2.2 Shared Systems, Structures, and Components/Unique Design Features

SSES consists of two units which have a common control room, diesel generators and refueling floor, turbine operating deck, radwaste system, and other auxiliary systems.

1.2.3 Associated Technical Specification Amendments

1.2.3.1 Average Power Range Monitor/Rod Block Monitor Technical Specifications/Maximum Extended Load Line Limit Analysis

The NRC issued Amendment No. 242 to Facility Operating License No. NPF-14 and Amendment No. 220 to Facility Operating License No. NPF-22 for SSES Units 1 and 2 on March 23, 2007. The amendments consisted of changes to the TSs in response to the licensee’s application dated November 18, 2005, as supplemented by letters dated November 29, 2006; December 1, 2006; December 15, 2006; January 9, 2007; and March 12, 2007 (two letters). These amendments revised the TSs for SSES Units 1 and 2 to allow the expanded operating domain resulting from the implementation of average power range monitor, rod block monitor technical specifications/maximum extended load line limit analysis (ARTS/MELLLA).

1.2.3.2 Standby Liquid Control System

The NRC issued Amendment No. 240 to Facility Operating License No. NPF-14 and Amendment No. 217 to Facility Operating License No. NPF-22 for SSES Units 1 and 2 on February 28, 2007. The amendments consisted of changes to the TSs in response to the licensee's application dated April 28, 2006. These amendments revised the SSES Unit 1 and 2 TSs to modify the standby liquid control system (SLCS) for single pump operation and the use of enriched sodium pentaborate solution.

1.2.3.3 Full-Scope Implementation of Alternate Source Term

The NRC issued Amendment No. 239 to Facility Operating License No. NPF-14 and Amendment No. 216 to Facility Operating License No. NPF-22 for SSES Units 1 and 2 on January 31, 2007. The amendments consisted of changes to the TSs in response to the licensee's application dated October 13, 2005, as supplemented by letters dated May 18, September 15 (two letters), September 29, October 20, November 14, December 13, and December 14, 2006. These amendments approved the full-scope implementation of an alternative source term (AST) methodology in accordance with 10 CFR 50.67, "Accident Source Term."

1.3 Licensee's Approach to Extended Power Uprate

The licensee prepared its application for the proposed EPU following the guidelines contained in General Electric Nuclear Energy (GENE) Licensing Topical Report (LTR) for Extended Power Uprate Safety Analysis, NEDC-33004P-A, "Constant Pressure Power Uprate," Revision 4, dated July 31, 2003. The NRC approved the constant pressure power uprate (CPPU) LTR (CLTR) in a safety evaluation (SE) dated March 31, 2003.

As part of its October 11, 2006, application (Reference 1), the licensee included as Attachment 4 the "Safety Analysis Report for Susquehanna Steam Electric Station Units 1 and 2, Constant Pressure Power Uprate," October 2006 (hereafter referred to as the Power Uprate Safety Analysis Report, or PUSAR). This PUSAR is an integrated summary of results of the safety analyses and evaluations performed specifically for the proposed CPPU for SSES Units 1 and 2. The PUSAR contains information that General Electric (GE) and AREVA, NP, Inc., consider proprietary. The report follows the generic content and format using the CPPU approach to uprating reactor power, as described in the CLTR. Attachment 6 to the PPL application contains a nonproprietary (i.e., publicly available) version of the PUSAR.

The licensee plans to implement the EPU in two steps for Unit 1. Specifically, the licensee plans to implement the first step of the uprate (an approximately 7-percent increase) upon startup (entry into Mode 2) from the spring 2008 Unit 1 refueling outage. The second step of the Unit 1 uprate is planned for completion upon startup from the spring 2010 Unit 1 refueling outage. For Unit 2, the licensee plans to implement the EPU in one step (i.e., the proposed 13-percent increase will occur in a single power ascension) upon startup from the spring 2009 Unit 2 refueling outage.

1.4 Plant Modifications

The modifications planned to support implementation of the SSES Unit 1 and 2 EPU analyses include the following:

- steam dryer replacements

- steam dryer vibration/acoustic monitoring instrumentation (Unit 1 only)
- cross-around relief valve setpoint change
- reactor feedwater pump seal
- power range neutron monitoring system
- ultimate heat sink (UHS) modifications
- ARTS/MELLLA (approved by prior amendment, implementation for Unit 2 completed)
- 10 CFR Part 50 Appendix R residual heat removal (RHR) pump logic change
- acid injection for cooling tower basin
- vibration/acoustic monitoring instrumentation on main steamlines (MSLs)
- neutron monitoring system settings
- electrohydraulic control (EHC) system modifications
- main steam isolation valve (MSIV) high-flow isolation setpoint
- reactor recirculation runback logic change
- reactor feedwater pump low suction pressure
- instrument calibration and computer software changes
- main generator rewind
- high-pressure (HP) turbine replacement
- condensate pump replacement
- feedwater (FW) heaters
- SLCS modifications (approved by prior amendment, implementation completed for Unit 2)
- circulating water box vents
- hydrogen water chemistry (HWC)
- main steam (MS), FW, and extraction steam piping supports

- #3 Feedwater Heater emergency dump valve replacement
- power distribution/switchyard modifications
- reactor feedwater pump turbines (RFPT) replacement
- condensate system modifications
- reactor water cleanup (RWCU) filter/demineralizer modifications

Section 2.0 of this SE provides the NRC staff's evaluation of the licensee's proposed plant modifications.

1.5 Method of NRC Staff Review

The NRC staff based its review of the SSES Unit 1 and 2 EPU application on NRC Review Standard (RS)-001, "Review Standard for Extended Power Uprates," issued December 2003. RS-001 contains guidance for evaluating each area of review in the application, including the specific general design criteria (GDC), given in Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities," used as the NRC's acceptance criteria. In its application (Reference 1), Attachment 12, PPL provided a markup of the review matrices contained in RS-001, with cross-references to the CLTR, as well as the SSES Unit 1 and 2 PUSAR and final safety analysis report (FSAR).

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 staff evaluated the licensee's application and supplements. The staff also performed audits of analyses supporting the EPU and performed independent calculations, analyses, and evaluations as noted below.

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 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 for the proposed EPU conditions. Section 2.0 of this SE provides details of the staff's review.

The NRC staff and its contractors conducted audits of the analyses supporting the proposed EPU in relation to the following topics:

- AREVA fuels methodology (see SE Section 2.8)
- long-term stability solution (see SE Section 2.8)

The NRC staff and its contractors performed independent confirmatory calculations, analyses, and evaluations in relation to the following topics:

- steam dryer structural integrity analyses (see SE Section 2.2)
- loss-of-coolant accident (LOCA) break analysis and peak cladding temperature (PCT) calculations (see SE Section 2.8)

2.0 EVALUATION

2.1 Materials and Chemical Engineering

2.1.1 Reactor Vessel Material 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. 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) GDC 14, "Reactor Coolant Pressure Boundary," which requires that the reactor coolant pressure boundary (RCPB) be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture, (2) GDC 31, "Fracture Prevention of Reactor Coolant Pressure Boundary," which 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, (3) Appendix H, "Reactor Vessel Material Surveillance Program Requirements," to 10 CFR Part 50, which provides for monitoring changes in the fracture toughness properties of materials in the RV beltline region, and (4) 10 CFR 50.60, "Acceptance Criteria for Fracture Prevention Measures for Light-Water Nuclear Power Reactors for Normal Operation," which mandates compliance with the requirements of Appendix H to 10 CFR Part 50. Standard Review Plan (SRP) Section 5.3.1, and other guidance provided in Matrix 1 of RS-001 contain specific review criteria.

Technical Evaluation

The NRC's regulatory requirements related to the establishment and implementation of a facility's RV materials surveillance program and surveillance capsule withdrawal schedule are given in Appendix H to 10 CFR Part 50. The regulations offer two specific alternatives with regard to the design of a facility's RV surveillance program that may be used to address the requirements of Appendix H. The first alternative is the implementation of a plant-specific RV surveillance program consistent with the requirements of American Society for Testing and Materials (ASTM) Standard Practice E 185, "Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels." In the design of a plant-specific RV surveillance program, a licensee may use the edition of ASTM Standard Practice E 185 which was current on the issue date of the ASME Code when the RV was purchased, or later editions through the 1982 edition.

The second alternative provided in Appendix H to 10 CFR Part 50 is the implementation of an integrated surveillance program (ISP). Appendix H defines the ISP as occurring when "the representative materials chosen for surveillance for a reactor are irradiated in one or more other reactors that have similar design and operating features."

The BWR Vessel and Internals Project (BWRVIP) ISP was submitted for NRC staff review and approval in proprietary topical reports BWRVIP-78, "BWR Vessel and Internals Project, BWR Integrated Surveillance Program Plan," dated December 22, 1999, and BWRVIP-86, "BWR Vessel and Internals Project, BWR Integrated Surveillance Program Implementation Plan," dated December 22, 2000. Letters from the BWRVIP to the NRC dated December 15, 2000, and May 30, 2001 provided additional information necessary to establish the technical basis for, and proposed implementation of, the BWRVIP ISP. The NRC staff approved the proposed BWRVIP ISP in an SE dated February 1, 2002 (ADAMS Accession No. ML020380691). However, the SE required that BWR licensees who wish to implement the BWRVIP ISP for their facilities provide plant-specific information. The plant-specific information must demonstrate that each reactor has an adequate dosimetry program and that there is adequate arrangement for sharing data between plants.

By letter dated July 25, 2002, the licensee submitted its LAR to change the SSES Unit 1 and 2 RV material surveillance program required by Appendix H to 10 CFR Part 50, which will incorporate the BWRVIP ISP into the SSES Unit 1 and 2 licensing basis. The PPL LAR also addressed the plant-specific information for SSES Units 1 and 2 required in the NRC staff's February 1, 2002, BWRVIP ISP SE. By letter dated November 8, 2002, the NRC staff evaluated the plant-specific information provided by the licensee to demonstrate that the BWRVIP ISP could be implemented at SSES Units 1 and 2. The staff concluded that the plant-specific information demonstrated that there is an adequate dosimetry program and that there is adequate arrangement for sharing data between plants. By providing the requested plant-specific information, the licensee has demonstrated the compliance of SSES Units 1 and 2 with the ISP requirements of Appendix H to 10 CFR Part 50.

In a request for additional information (RAI) dated March 29, 2007, the NRC staff asked the licensee about the projected fluence of the SSES Unit 1 120-degrees azimuth capsule at its scheduled withdrawal date of 2012, taking into account EPU conditions. The staff also asked the licensee to provide an evaluation of the acceptability of removing this capsule based on its updated projected fluence and its intended purpose within the BWRVIP ISP. In its response, dated April 26, 2007, the licensee stated the following:

> The projected fluence for the SSES, Unit 1 120 degrees azimuth capsule at the scheduled withdrawal in 2012 is 5.5E17 n/cm^2. This projection was determined using the RAMA code. The analysis includes EPU conditions. The analysis has been submitted to the BWRVIP Project Manager as required by the programmatic requirements of BWRVIP-86A.
>
> The SSES, Unit 1 120 degrees azimuth capsule will be representative of the facilities identified as relying on it in BWRVIP-78 and BWRVIP-86-A when withdrawn in 2012. The data from the capsule will be representative because PPL will follow the protocols of BWRVIP-86A. The withdrawal, decontamination, and shipping technical and programmatic requirements of BWRVIP-86A will be met. Note that BWRVIP-78 has been superseded by the NRC approved BWRVIP-86A.

The NRC staff found this response acceptable. Therefore, the licensee has satisfied the contingency of Appendix H, Section III.(C)(1)(d), to 10 CFR Part 50.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the RV surveillance withdrawal schedule and concludes that the licensee has adequately addressed changes in neutron fluence and their effects on the schedule. The staff further concludes that the RV capsule withdrawal schedule is appropriate to ensure that the RV 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 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, "Fracture Toughness Requirements," to 10 CFR Part 50 provides fracture toughness requirements for ferritic materials (low-alloy steel or carbon steel) in the RCPB, including requirements for the upper-shelf energy (USE) values used for assessing the 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 (AOOs) and hydrostatic tests. The NRC staff's review of P-T limits covered the methodology and the calculations for the number of effective full-power years (EFPYs) specified for the proposed EPU, considering neutron embrittlement effects and using linear elastic fracture mechanics.

The NRC's acceptance criteria for USE and P-T limits evaluations 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 abnormal leakage, of rapidly propagating failure, and of gross rupture, (2) GDC 31, which 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 insofar as it requires that the RCPB be designed and constructed so as to have an exceedingly low probability of gross rupture or significant leakage, (3) Appendix G to 10 CFR Part 50, which specifies fracture toughness requirements for ferritic components of the RCPB, and (4) 10 CFR 50.60, which requires compliance with the requirements of Appendix G to 10 CFR Part 50. SRP Section 5.3.2 and other guidance provided in Matrix 1 of RS-001 contain specific review criteria.

Technical Evaluation

USE Value Calculations

Appendix G to 10 CFR Part 50 provides the staff's criteria for maintaining acceptable levels of USE for the RV beltline materials of operating reactors throughout the licensed lives of the facilities. The rule requires RV beltline materials to have a minimum USE value of 75 ft-lb in the unirradiated condition and to maintain a minimum USE value above 50 ft-lb throughout the life of the facility, unless analyses can demonstrate that lower values of USE would provide acceptable margins of safety against fracture equivalent to those required by Appendix G to Section XI of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code). The rule also mandates that the methods used to calculate USE values must account for the effects of neutron irradiation on the USE values for the materials and must incorporate any relevant RV surveillance capsule data that are reported through implementation of a plant's Appendix H to 10 CFR Part 50 RV materials surveillance program.

By letter dated April 30, 1993, the Boiling Water Reactor Owners Group (BWROG) submitted a topical report entitled, "10 CFR 50, Appendix G Equivalent Margins Analysis for Low Upper Shelf Energy in BWR/2 Through BWR/6 Vessels," to document that BWR RVs can meet the margins of safety against fracture equivalent to those required by Appendix G to Section XI of the ASME Code for Charpy USE values less than 50 ft-lb. In a letter dated December 8, 1993, the NRC staff concluded that the topical report demonstrates that the materials evaluated have the margins of safety against fracture equivalent to those in Appendix G to Section XI of the ASME Code, in accordance with Appendix G to 10 CFR Part 50. In this report, the BWROG derived through statistical analysis the initial USE values for materials that originally did not have documented Charpy USE values. Using these statistically derived Charpy USE values, the BWROG predicted the end-of-life (40 years of operation) USE values in accordance with Position 1.2 in Regulatory Guide (RG)1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," issued May 1988. According to this RG, the decrease in USE depends on the amount of copper in the material and the neutron fluence predicted for the material. The BWROG analysis determined that the minimum allowable Charpy USE value in the transverse direction for base metal and along the weld for weld metal was 35 ft-lb.

GE performed an update to the USE equivalent margins analysis (EMA), which is documented in Electric Power Research Institute (EPRI) TR-113596, "BWR Vessel and Internals Project BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines (BWRVIP-74)," issued September 1999. EPRI TR-113596 provides a bounding Charpy USE evaluation for BWR plants for 54 EFPYs. The analysis in EPRI TR-113596 determined the reduction in the unirradiated Charpy USE resulting from neutron radiation using the methodology in Position 1.2 in RG 1.99. Using this methodology and a correction factor of 65 percent for conversion of the longitudinal properties to transverse properties, the lowest Charpy USE at 54 EFPYs for all BWR/3–6 plates is projected to be 45 ft-lb. The correction factor for specimen orientation in plates is based on NRC Branch Technical Position (BTP) MTEB 5-2, "Fracture Toughness Requirements." Using the RG methodology, the lowest Charpy USE at 54 EFPY for shielded metal arc welds is projected to be 51.1 ft-lb. Since the value for the BWR/3–6 plates is greater than the 35 ft-lb minimum allowable, this will meet the margins of safety against fracture equivalent to those required by Appendix G to 10 CFR Part 50, and the value for the shielded metal arc weld is greater than the 50 ft-lb criteria given in that appendix.

EPRI TR-113596 indicates that the percent reductions in Charpy USE for the limiting BWR/3–6 plates and shielded metal arc welds are 23.5 percent and 39 percent, respectively. Therefore, to demonstrate that beltline materials meet the criteria specified in the report, licensees must show that the projected percent reductions in Charpy USE for their beltline materials are less than those specified for the limiting BWR/3–6 plates and shielded metal arc welds. Licensees also have to show that the actual percent reductions in Charpy USE for their surveillance welds and plates are less than or equal to the values projected using the methodology in Position 1.2 in RG 1.99. Beltline materials that meet these criteria will meet the margins of safety against fracture equivalent to those required by Appendix G to 10 CFR Part 50.

In an RAI dated March 29, 2007 (ADAMS Accession No. ML070860866), the NRC staff asked the licensee to provide a table demonstrating how it calculated the end-of-license USE values for all reactor pressure vessel (RPV) beltline materials, considering EPU conditions. In addition, the licensee should show how it meets the requirements of Appendix G to 10 CFR Part 50 directly, or through application of the EMA of BWRVIP-74, for the limiting plate/forging and weld materials for each of the SSES RPVs.

In its response, dated April 26, 2007 (ADAMS Accession No. ML071280506), the licensee provided tables for SSES Units 1 and 2 that show the effect of EPU conditions on USE values. The licensee also showed how it would meet the requirements of Appendix G to 10 CFR Part 50. Specifically, the licensee showed that the limiting plates and welds at the end of the 40-year license with power uprate conditions would not surpass 12.8-percent drop in USE for either unit. The NRC staff independently confirmed these percent drop USE values for the SSES Unit 1 and 2 plates and welds using the methodology in RG 1.99. The NRC staff agrees with the conclusions reached by the licensee. However, some of the values in the licensee's tables show a conservative representation that may be misleading. In particular, the unirradiated USE values whose footnote reads "value is based in 10 °F (or 40 °F) data, since the initial USE value is not available" may not be accurate. Since this will cause the calculations to err conservatively, the NRC staff still agrees with the conclusions. The percent drop in USE values remains valid.

Therefore, the NRC staff concludes that the licensee has demonstrated that the SSES Unit 1 and 2 RVs comply with the requirements of Appendix G to 10 CFR Part 50, through the end of each unit's 40-year operating license by either (1) demonstrating that a material's USE value will remain above 50 ft-lb or (2) meeting the EMA criteria in the BWRVIP-74 report.

P-T Limit Calculations

Section IV.A.2 of Appendix G to 10 CFR Part 50 requires that the P-T limits for operating reactors be at least as conservative as those that would be generated if the methods of calculation in Appendix G, Section XI, to the ASME Code were used to calculate the P-T limits. The rule also requires that the P-T limit calculations account for the effects of neutron irradiation on the RV beltline materials and incorporate any relevant RV surveillance capsule data that are required to be reported as part of the licensee's implementation of its Appendix H to 10 CFR Part 50 RV materials surveillance program.

Section 2.1.1 of Attachment 13 in Reference 1, submitted by the licensee, indicates that the P-T limit curves contained in the TSs remain bounding for EPU conditions. The SSES Unit 1 and 2 P-T limit curves were approved by Amendment No. 232 for Unit 1 and Amendment No. 209 for Unit 2, dated March 30, 2006. The P-T limit curves approved in the NRC staff's March 30, 2006, SE account for CPPU operating conditions up to 3952 MWt and are acceptable for up to 35.7 EFPYs of operation for SSES Unit 1 and 30.2 EFPYs of operation for SSES Unit 2. Therefore, the NRC staff finds the proposed EPU acceptable with respect to P-T limits.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the USE values for the RV beltline materials and P-T limits for the plant. The staff concludes that the licensee has adequately addressed changes in neutron fluence and their effects on the USE values for SSES Unit 1 and 2 RV beltline materials and the P-T limits for the plant. The staff also concludes that the SSES Unit 1 and 2 beltline materials will continue to have acceptable USE, as mandated by Appendix G to 10 CFR Part 50, through the expiration of the current operating license. As documented in the NRC staff's March 30, 2006, SE, the licensee has demonstrated the validity of the SSES Unit 1 and 2 P-T limits for operation under the proposed EPU conditions through 35.7 and 30.2 EFPY, respectively. Based on this, the staff concludes that the SSES Unit 1 and 2 RVs will continue to meet the requirements of Appendix G to 10 CFR Part 50 and 10 CFR 50.60 and will comply with GDC 14 and 31 in this respect, following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to RV material USE values and the proposed P-T limits.

2.1.3 Reactor Internal and Core Support Materials

Regulatory Evaluation

The RV internals and core supports include structures, systems, and components (SSCs) that perform safety functions or 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 reactor coolant system (RCS). The NRC staff's review covered the materials' specifications and mechanical properties, welds, weld controls, nondestructive examination procedures, corrosion resistance, and susceptibility to degradation. The NRC's acceptance criteria for RV internals and core support materials are based on GDC 1, "Quality Standards and Records," and 10 CFR 50.55a, "Codes and Standards," for material specifications, controls on welding, and inspection of reactor internals and core supports. SRP Section 4.5.2, BWRVIP-26 ("BWR Top Guide Inspection and Flaw Evaluation Guidelines"), and Matrix 1 of RS-001 contain specific review criteria.

Technical Evaluation

Reactor internals and core support materials are subject to the following degradation mechanisms:

- crack initiation and growth resulting from stress-corrosion cracking (SCC), intergranular stress-corrosion cracking (IGSCC), and irradiation-assisted stress-corrosion cracking (IASCC)
- crack initiation and growth resulting from flow-induced vibration (FIV)
- cumulative fatigue damage
- loss of fracture toughness as a result of thermal aging and neutron embrittlement

Crack initiation and growth and loss of fracture toughness as a result of thermal aging and neutron embrittlement are managed through the inservice inspection program that conforms to the requirements of 10 CFR 50.55a and the BWRVIP program. The BWRVIP inspection program supplements the inservice inspection program required by 10 CFR 50.55a. The NRC reviews and approves the BWRVIP program.

The licensee's supplemental submittal, dated March 14, 2007, indicates that SSES Units 1 and 2 belong to the BWRVIP organization, and implementation of the procedurally controlled program is consistent with the BWRVIP-issued documents. The inspection strategies recommended by the BWRVIP consider the effects of fluence on the applicable components and are based on component configuration and field experience. Reactor water chemistry conditions are maintained consistent with the established EPRI, BWRVIP, and industry guidelines, except where technical justifications in accordance with the BWRVIP-94 report, "Program Implementation Guide," have been documented.

Note 1 in Matrix 1 of Section 2.1 of RS-001, Revision 0, indicates that the BWRVIP-26 report provides guidance on the neutron-irradiation-related threshold for inspection for IASCC in BWRs. The "Final License Renewal SER for BWRVIP-26," dated December 7, 2000, states that the threshold fluence level for IASCC is $5x10^{20}$ neutrons per square centimeter (n/cm^2) ($E > 1$ MeV).

The licensee, in response to an NRC staff RAI dated April 30, 2007 (ADAMS Accession No. ML071140343), provided supplemental information by letters dated May 21, 2007 (ML071500300) and June 8, 2007 (ML071710442), regarding each of the reactor components that will exceed the threshold of $5x10^{20}$ n/cm^2 ($E > 1$ megaelectronvolts (MeV)) and its current inspection program to be used in managing IASCC. The shroud, the in-core flux monitoring dry tube assembly, and the top guide will exceed the threshold.

The licensee responded with the following information about the inspection program for the shroud:

> The shroud inspections are performed in accordance with the BWRVIP-76 Core Shroud Inspection and Flaw Evaluation Guidelines. BWRVIP-76 defines the scope, sample size, inspection method, frequency of examination and acceptance criteria. The SSES shrouds are classified as Category C per BWRVIP-76. SSES has inspected all horizontal shroud welds (H1, H2, H3, H4, H5, H6A, H6B and H7) and all shroud vertical welds per the BWRVIP-76 requirements. Only portions of H4 and H5 welds and their associated vertical welds will exceed 5E20 n/cm^2. The horizontal welds are inspected ultrasonically. The vertical welds have been inspected using both EVT-1 and ultrasonics. Only one vertical weld between H4 and H5 on the SSES, Unit 1 shroud contains a short non-through wall flaw. All horizontal welds on the SSES, Unit 1 and 2 shrouds contain non-through wall flaws except weld H3, which has no relevant indications. Inspection frequency and scope of future inspections will be based on the results of the next inspection in 2009 (U2) and 2010 (U1). Crack growth rate and fracture toughness for all identified flaws has been evaluated for the affects of fluence in accordance with BWRVIP-76. These evaluations verify structural integrity and define the inspection frequency.

The licensee responded with the following information about the inspection program for the in-core flux monitoring dry tube assembly:

> The upper part of the dry tube assembly is located within the reactor core, adjacent to fuel assemblies. As such, they are exposed to high fluence. Therefore, it is assumed that the dry tubes will exceed the IASCC threshold with or without EPU. However, BWRVIP-47-A, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines, does not require inspection of in-core flux monitoring dry tube assemblies. BWRVIP-47-A, Section 2.3.3 states the basis for not

> requiring inspection is that the failure of the dry tubes does not impair safe shutdown. The PPL inspection program for dry tubes is based on GE SIL 409, Revision 2. PPL has replaced all the dry tube assemblies with the dry tubes that are constructed with IASCC-resistant material. The upper two feet of these dry tube assemblies will be inspected visually for damage within 20 years of the replacement date and every two outages thereafter.

The NRC staff determined that the responses for the shroud and the in-core flux monitoring dry tube assemblies were acceptable. Additionally, the staff determined that the licensee appropriately confirmed that the core plate, in-core flux monitoring guide tubes, and control rod guide tubes were considered in the determination of which components will exceed the BWRVIP-26 threshold fluence level. None of these components will exceed the threshold.

The licensee responded with the following information about the inspection program for the top guide:

> The top guide inspections are performed in accordance with the BWRVIP-26-A BWR Top Guide Inspection and Flaw Evaluation Guidelines. BWRVIP-26-A defines the scope, sample size, inspection method, frequency of examination and acceptance criteria. The SSES Units utilize wedges to provide lateral support and to increase the seismic margin of the top guides. For this configuration, BWRVIP-26-A requires the inspection of the top guide hold down assemblies only. All hold down assemblies are visually inspected every 10 years. The grid beams, whose fluence exceeds the IASCC threshold, are not required to be inspected. BWRVIP-26-A, Section 2.2.1 states, "There are no safety consequences resulting from failure at a single beam intersection. Failure of an upper beam would have no consequence, and failure of a lower beam may cause some core instrument damage but would not affect safe shutdown. Also, grid beams are interlaced such that a large number of complete separations would need to occur before control rod insertion would be affected."

In the response concerning the top guide, the licensee stated that the grid beams are not required to be inspected. The licensee based this statement on BWRVIP-26-A, which states that there are no safety consequences resulting from a failure at a single beam intersection and that a large number of complete separations would need to occur before control rod insertion would be affected. In other words, BWRVIP-26 acknowledges that while there is no safety concern from a single beam failure, multiple beam failures would be a safety concern, as they would compromise the safe shutdown of the reactor.

The NRC staff notes that multiple failures of the top guide beams are possible when the threshold fluence for IASCC is exceeded. For example, according to BWRVIP-26-A, multiple cracks have been observed in the top guide beams at the Oyster Creek Nuclear Generation Station. In addition, multiple failures have occurred in other components that have exceeded the threshold fluence for IASCC, such as baffle-former bolts in pressurized-water reactors.

The NRC staff also notes that it informed the BWRVIP of this issue by letter dated June 10, 2003. This letter recommended that the BWRVIP conduct a comprehensive evaluation of the impact of IASCC and multiple failures of the top guide beams and that BWRVIP should develop an inspection program for top guide beams that exceed the IASCC threshold fluence for all BWRs to ensure that they can meet the requirements of 10 CFR Part 54, "Requirements for

Renewal of Operating Licenses for Nuclear Power Plants" (continue to perform their intended function under the current licensing basis for the extended period of operation). At the time, the NRC believed that the IASCC fluence threshold would be exceeded during the extended period of operation. However, the NRC now has information that some plants have already exceeded the IASCC fluence threshold during the current operating period. Therefore, since this degradation mechanism is based on exceeding the IASCC fluence threshold, this issue may also apply to the current operating period. The BWRVIP is working to resolve this issue generically, but until then, a plant-specific inspection program is necessary to manage the effects of IASCC in the top guide.

Matrix 1 of RS-001, Revision 0, specifies that the NRC's acceptance criteria for reactor internals and core support materials are based on GDC 1 of Appendix A to 10 CFR Part 50. GDC 1 specifies, "where generally recognized codes and standards are used, they shall be identified and evaluated to determine their applicability, adequacy, and sufficiency and shall be supplemented or modified as necessary to assure a quality product in keeping with the required safety function." Therefore, since the current inspection plan of excluding inspections of the top guide beam is not adequate to address the safety concern of multiple grid beam failures impacting the safe shutdown of the reactor, the inspection plan must be supplemented to meet the requirement of GDC 1. The licensee can accomplish this modification by providing, for NRC approval, an inspection program to manage this aging effect to preclude loss of the component intended function.

In its RAI dated April 30, 2007, the NRC staff requested that the licensee provide an inspection program to manage the IASCC degradation mechanism of the top guide grid beams to preclude the loss of component intended function, as required by GDC 1.

In its response dated June 8, 2007, the licensee provided the following regulatory commitment related to its inspection program for the top guide grid beams:

> Enhanced visual testing (EVT-1) of the top guide grid beams will be performed in accordance with GE SIL 554 following the sample selection and inspection frequency of BWRVIP-47 for CRD guide tubes. That is, inspections will be performed on 10% of the total population of cells within twelve years, and 5% of the population within six years. The sample locations selected for examination will be in areas that are exposed to the highest fluence. This inspection plan will be implemented beginning with the refueling outage following EPU operation. This inspection plan will be implemented until an NRC approved resolution is developed in accordance with the BWRVIP and implemented at SSES, Unit 1 and 2.

The NRC staff finds this program to be acceptable because the top guide grid beams will be inspected to ensure that multiple grid beam failure does not occur.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the susceptibility of reactor internals 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 these components. The NRC staff further concludes that the licensee has demonstrated that the reactor internals and core support materials will continue to be acceptable and will continue to meet the requirements of GDC 1 and 10 CFR 50.55a with respect to material specifications, welding controls, and inspection following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to reactor internals and core support materials.

The NRC staff has determined that under the proposed EPU conditions, adequate safety margins will be maintained through the end of the 40-year license term for the following RV and RV internals structural integrity assessments:

- the RV surveillance program
- the RV USE assessment
- the RV P-T limits
- structural integrity assessment of the SSES Unit 1 and 2 RV internal components

2.1.4 Protective Coating Systems (Paints)—Organic Materials

Regulatory Evaluation

Organic paints are protective coating systems that protect 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 design-basis accident (DBA) conditions, considering radiation and chemical effects. The NRC's acceptance criteria for protective coating systems are based on (1) Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," to 10 CFR Part 50, which provides quality assurance requirements for the design, fabrication, and construction of safety-related SSCs, and (2) RG 1.54, Revision 1, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants," issued July 2000, for application and performance monitoring guidance of coatings in nuclear power plants. SRP Section 6.1.2 contains specific review criteria.

Technical Evaluation

SSES Units 1 and 2 have Service Level I coatings subject to the requirements of RG 1.54 and American National Standards Institute (ANSI) Standard N101.4-1972, "Quality Assurance for Protective Coatings Applied to Nuclear Facilities." The licensee did not impose the criteria of RG 1.54 on the paint material or application for the nuclear steam supply system (NSSS) because most of these components were ordered before RG 1.54 was issued. According to the updated final safety analysis report (UFSAR), and the licensee's letter dated May 3, 2007, the coatings on NSSS components were qualified according to the requirements and guidelines of ANSI N101.2, "Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities." Coatings on the drywell liner and structural steel in the drywell were qualified in accordance with ANSI N101.2 and applied in accordance with RG 1.54.

The qualified coatings include inorganic zinc (with and without epoxy topcoat), epoxy topcoat (with and without inorganic zinc), and epoxy concrete surfacer. In its letter dated June 8, 2007, the licensee discussed the conditions used to qualify Service Level I protective coatings in containment and whether the qualification test conditions remain bounding for DBA conditions following the proposed EPU. The qualification test conditions of 1×10^9 rad total integrated dose, 340 °F, and 70 pounds per square inch gauge (psig) exceed the values of $9x10^8$ rad, 337 °F, and 49 psig, which correspond to the values expected in containment following a postulated LOCA at the proposed power uprate conditions.

A large portion of the inorganic zinc coating in both units was applied without the documentation or procedures required for qualification but was later qualified by in situ testing as discussed below. This coating was applied to pipe supports and hangers, non-NSSS equipment, and ductwork. For the in situ testing, samples were made from coated support steel removed from the containment, and the number of samples was proportional to the surface area of painted steel in that sector. The coupons were subjected to a simulated design-basis LOCA for 7 days at the test conditions described above for qualification testing.

In its PUSAR, the licensee estimated the amount of coating debris that would contribute to the emergency core cooling system (ECCS) suction strainer debris loading following a postulated design-basis LOCA. In a letter dated May 3, 2007, the licensee stated that all of the qualified coating (604 ft^2) in the path of the LOCA jet is assumed to fail in the form of particulate, which is consistent with the guidance in topical report NEDO-32686, Revision 1, "Utility Resolution Guidance for ECCS Suction Strainer Blockage." In addition, all of the unqualified coating in the drywell is assumed to fail in the form of flakes. In the suppression pool, all of the inorganic zinc and a portion of unqualified red oxide are assumed to fail in the form of flakes. The licensee stated that the proposed power uprate does not affect the amount of coatings debris generated in a postulated LOCA because the existing evaluation is based on assumptions that are bounding for power uprate conditions.

In its RAI response dated May 3, 2007 (ADAMS Accession No. ML071360036), the licensee provided additional information requested by the NRC staff about the plant requirements for inspecting, removing, and replacing degraded containment coatings and the effects of EPU conditions on these activities. During refueling and inspection outages, walkdown inspections are performed on containment coatings in accordance with ASTM Standard D5163, "Standard Guide for Establishing Procedures to Monitor the Performance of Safety Related Coatings in an Operating Nuclear Power Plant." This is one of a series of ASTM standards for personnel, quality assurance, and performance related to coatings applications at nuclear power plants and referenced in RG 1.54. These ASTM standards replaced ANSI N101.2 and N101.4, which were withdrawn in 1988. The licensee stated that the proposed power uprate would not affect the frequency of inspection or coating degradation because the temperature and pressure inside containment during normal operations would not change and the increase in radiological dose rate would remain within the range for which the coatings were qualified. Based on the information discussed above, the NRC staff finds that the licensee's activities on coatings qualification testing, inspection, and maintenance will continue to meet the positions of RG 1.54 at power uprate conditions.

In addition to paints, other organic materials such as cable insulation can be exposed to DBA conditions which could degrade the material and generate organic gases and hydrogen. In its RAI response dated May 3, 2007, the licensee discussed the effect of power uprate conditions on the generation of hydrogen and organic gases in containment following a postulated LOCA. The licensee stated that because organic materials are a minor source of hydrogen gas and because the changes in the post-LOCA environment (particularly the temperature) resulting from uprate conditions would be small, the amount of additional gas generation from organic materials would be insignificant. With respect to maintaining pH above 7 in a post-LOCA suppression pool environment, the licensee has completed an evaluation for power uprate conditions.

Conclusion

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

2.1.5 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 caused by 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 the licensee could repair or replace damaged components before they reach a critical thickness. The licensee's FAC program consists of predicting loss of material using the EPRI 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 SSES Units 1 and 2 is based on selective component inspections according to guidance in EPRI NSAC-202L-R3, "Recommendations for an Effective Flow-Accelerated Corrosion Program," issued 2006. The program includes plant-specific CHECWORKS models for each unit to predict corrosion rate and remaining service life for components containing single- and two-phase fluids. The CHECWORKS program is used to model and evaluate piping systems to focus inspection resources on the locations most susceptible to degradation. The plant-specific CHECWORKS model provides quantitative estimates of FAC rates and times to reach the minimum allowable wall thickness. Inputs to the model include plant operating parameters, component material and design features, and inspection results. According to its October 11, 2006, application (Reference 1), the licensee updates the CHECWORKS FAC model after each refueling outage at a minimum.

In its RAI response dated May 3, 2007, the licensee described how scoping is performed and components are prioritized for inspection. Scoping to identify susceptible components is performed using the criteria of NSAC-202L-R3 and considering the CHECWORKS modeling capabilities. The CHECWORKS model includes susceptible components if they meet the modeling criteria (e.g., defined operating conditions). Susceptible piping that cannot be modeled is in the plant's susceptible nonmodeled (SNM) program. The susceptibility evaluation also identifies locations that may be susceptible to other (non-FAC) flow-related thinning mechanisms such as cavitation and liquid droplet impingement.

Components modeled in CHECWORKS are prioritized based on the results of the wear (corrosion) rate analysis. SNM lines are prioritized based on consequences of failure and susceptibility. If consequences of failure are potentially high (e.g., personnel safety), FAC susceptibility is assigned based on industry experience, plant experience, and operating conditions. These SNM components are then prioritized based on relative rankings provided by a CHECWORKS analysis of the system parameters, operating experience at SSES and elsewhere in the industry, or other analysis methods based on industry guidance (e.g., EPRI).

The licensee summarized the inspection and evaluation process in its October 11, 2006, May 3, 2007, and July 12, 2007, submittals. Component thickness is measured using ultrasonic testing, which is judged the most suitable technique in NSAC-202L for measuring remaining wall thickness. The grid size and layout are specified in accordance with the recommendations in NSAC-202L-R3. The licensee evaluates suitability for continued service based on the methods in that report and using the corrosion rate calculated from the thickness measurements and operating time and the design code minimum allowable wall thickness. The minimum allowable wall thickness is calculated using circumferential and axial stress inputs. Components are replaced with FAC-resistant materials (steel containing at least 1.25-percent chromium or clad with stainless steel) if the thickness projected at the subsequent outage is less than the allowable thickness.

The criteria for selecting components for inspection will not change as a result of EPU. Rather, power uprates affect the parameters that influence FAC, including temperature, moisture content, water chemistry (including dissolved oxygen), flow geometry, and velocity. Another parameter that influences FAC but is not EPU-dependent is the material (alloy) composition. According to the licensee's application, the EPU proposed for SSES would affect moisture and oxygen content in the fluid, temperature, and flow velocity. Although the values of these parameters will change in many locations, they will remain within the range that can be modeled in the SSES CHECWORKS program.

In its RAI response dated June 1, 2007 (ADAMS Accession No. ML071620218), the licensee compared pre-EPU and post-EPU corrosion rate predictions (from CHECWORKS) for the 10 components with the highest post-EPU FAC rates. (These are the same components with the highest pre-EPU FAC rates.) Eight of these components are in Unit 1. The NRC staff finds the corrosion rate changes (increases up to 12 percent and decreases up to 24 percent) reasonable for the corresponding changes in operating conditions. Based on the changes, the licensee expects to add more FAC inspection locations. Candidate locations identified in the application include FW piping, turbine cross-around piping, and moisture separator drains because of anticipated flow velocity increases of about 15 percent.

In its supplemental response dated July 12, 2007 (ADAMS Accession No. ML072010019), the licensee discussed the measured and predicted thickness values and provided examples for 10 components with relatively high corrosion rates. For nine of the components, the measured thickness was greater than predicted (i.e., conservative) by up to a factor of about 10. In one case, the measured thickness was less than predicted, although the difference (0.011 inches was small relative to the measured thickness (0.400 inches). The licensee explained that because the CHECWORKS models were developed recently (2005), they are still in a "calibration" phase and do not yet provide the best possible predictions. Rather, past predictions have been calculated based on conservative analysis of the inspection data. The NRC staff finds this approach acceptable because the predictive capability of the model will increase with additional inspection data, and the licensee does not plan to reduce the number of monitored components before the model is calibrated.

The EPRI report NSAC-202L-R3 provides separate guidance for small-bore piping because of differences relative to large-bore piping, including the limited knowledge of local operating conditions and the geometry of socket-weld connections. The licensee described its program for small-bore piping in its RAI response dated May 3, 2007. The SNM program described above addresses the licensee's small-bore piping (0.5 to 2 inches in diameter). This approach is consistent with the guidance in NSAC-202L-R3 because these systems are categorized according to the consequences of failure and, in the case of consequences greater than minimal, prioritized for inspection based on susceptibility to FAC. If significant thinning is detected, the licensee replaces the entire pipeline with FAC-resistant material.

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 that the licensee has adequately addressed the impact of changes in plant operating conditions. Further, the NRC staff concludes that the licensee has demonstrated that 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.

2.1.6 Reactor Water Cleanup System

Regulatory Evaluation

The RWCU system provides a means for maintaining reactor water quality by filtration and ion exchange and a path for removal of reactor coolant when necessary. Portions of the RWCU system comprise the RCPB. The NRC staff's review of the RWCU system included component design parameters for flow, temperature, pressure, heat removal capability, and impurity removal capability and the instrumentation and process controls for proper system operation and isolation. The review consisted of evaluating the adequacy of the plant's TSs in these areas under the proposed EPU conditions. The NRC's acceptance criteria for the RWCU system are based on (1) 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, (2) GDC 60, "Control of Releases of Radioactive Materials to the Environment," insofar as it requires that the plant design include a means to control the release of radioactive effluents, and (3) GDC 61, "Fuel Storage and Handling and Radioactivity Control," insofar as it requires that systems that contain radioactivity be designed with appropriate confinement. SRP Section 5.4.8 contains specific review criteria.

Technical Evaluation

Since the RWCU system continuously takes a portion of the reactor water, the NRC staff evaluated potential changes to the system resulting from the power uprate. The licensee's evaluation of the RWCU system, as provided in the PUSAR, concluded that changes to the system would be insignificant to the system performance. The licensee summarized its evaluation of the RWCU system in its RAI response dated May 3, 2007. This evaluation included the RWCU pumps, heat exchangers, demineralizers, flow control valves, and water chemistry.

With respect to the RWCU pumps, the temperature is expected to decrease about 2 °F and the discharge pressure would increase about 10 psi because of the higher FW flow. The licensee stated that these changes are within the capabilities of the pumps and flow control valves. For the heat exchangers, the flow rates, velocities, pressure drops, and heat duty will not change as a result of the power uprate. Likewise, the flow rate through the filter/demineralizers will not change. Based on the magnitude of these changes, the NRC staff agrees that these parameters will not challenge the RWCU system design or affect operation significantly.

Under the proposed EPU conditions, the MS flow rate at normal operating conditions would increase from about 14.4 million pounds per hour (Mlb/h) to about 16.5 Mlb/h.
The design maximum and operating flow rate through the RWCU system is 146,300 lb/h. Since the RWCU system flow rate will not change as a result of the power uprate, the percentage of MS flow routed to the RWCU system would decrease from about 1.0 percent to 0.89 percent. The guidance from SRP Section 5.4.8 is that the RWCU system flow rate should be approximately 1 percent of the MS flow rate.

According to the application (Reference 1), the licensee’s calculations indicate reactor water conductivity will increase from about 0.107 to 0.115 micro-mho per centimeter (µmho/cm) in Unit 1 and from about 0.130 to 0.141 µmho/cm in Unit 2. This is attributed to the higher FW flow rate and will increase the reactor water iron concentration from about 11.55 to 13.24 parts per billion (ppb) in Unit 1 and from about 7.5 to 8.6 ppb in Unit 2. According to the licensee’s May 3, 2007, letter, the concentration of iron in the FW is controlled by chemical addition to the FW, which will continue to be maintained within the plant limits of 0.1 to 1.0 ppb. The higher FW flow rate will also increase the chloride and sulfate levels, but most of the existing margin between the reactor water concentrations and operational limits will be retained at power uprate conditions.

The licensee’s May 3, 2007, letter, also described modifications to the RWCU system that are expected, based on results at other BWR plants, to improve filtration and ion exchange capability. The licensee’s evaluation discussed above did not include these modifications.

In its RAI response dated May 3, 2007, the licensee explained that the increase in the amount of impurities passing through the RWCU system because of the higher FW flow will make it necessary to backwash the RWCU system filter/demineralizer and replace the resin more frequently to maintain reactor water chemistry. The backwash interval is expected to decrease from about 5.25 days under current operating conditions to about 4.61 days at power uprate conditions, but this additional liquid and solid radwaste is small relative to the system capacity.

The licensee discussed its evaluation of RWCU system containment isolation valves in its RAI response dated May 3, 2007. This evaluation, which included a tabular summary, concluded that there would be no impact on the operation of these valves resulting from the small changes in environmental conditions (e.g., FW temperature), the lack of change in functional requirements and design-basis differential pressure, and the lack of sensitivity to conditions affected by power uprate (e.g., valves operated manually).

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the RWCU system and concludes that the licensee has adequately addressed changes in impurity levels and pressure and their effects on the system. The staff further concludes that the licensee has demonstrated that the RWCU system will continue to be acceptable following implementation of the proposed EPU and will continue to meet the requirements of GDC 14, 60, and 61. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the RWCU system.

2.1.7 Reactor Coolant Pressure Boundary Materials

The RCPB defines the boundary of systems and components containing the HP fluids produced in the reactor. The NRC staff's review of RCPB materials covered their 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, "Environmental and Dynamic Effects Design Bases," 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 abnormal leakage, rapidly propagating failure, and gross rupture, (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) Appendix G to 10 CFR Part 50, which specifies fracture toughness requirements for ferritic components of the RCPB. SRP Section 5.2.3 and other guidance provided in Matrix 1 of RS-001 contain specific review criteria. Additional information regarding primary water SCC of dissimilar metal welds and associated inspection programs appears in Generic Letter (GL) 97-01 ("Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations," dated April 1, 1997), Information Notice (IN) 00-17 ("Crack in Weld Area of Reactor Coolant System Hot Leg Piping at V.C. Summer," dated October 18, 2000), and Bulletin 01-01 ("Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," dated August 3, 2001), Bulletin 02-01 ("Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," dated March 18, 2001), and Bulletin 02-02, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs," dated August 9, 2002). A letter from C. Grimes, NRC, to D. Walters, Nuclear Energy Institute (NEI), dated May 19, 2000, contains additional review guidance for thermal embrittlement of cast austenitic stainless steel components.

Technical Evaluation

The RCPB piping at SSES Units 1 and 2 evaluated for the EPU at the CPPU conditions includes the (1) reactor recirculation system (RRS), (2) control rod drive system (CRDS), (3) RHR low-pressure coolant injection (LPCI) lines, (4) core spray (CS) injection lines, (5) SLCS injection line, (6) RPV bottom head drain line, (7) MS piping system and associated branch piping, (8) FW piping system, and (9) RCPB portion of the RPV head spray and vent lines, RV to safety relief valve (SRV) discharge piping and RWCU piping. The licensee's evaluation determined that the proposed EPU will not significantly affect the RCPB piping considering the potential changes in temperature, pressure, flow, and mechanical loading resulting from the EPU. The NRC staff finds the licensee's conclusion acceptable because it performed the evaluation in accordance with the processes identified in licensing topical reports (CLTR, NEDC-32424P-A (ELTR1), and NEDC-32523P-A (ELTR2)) previously reviewed and approved by the NRC staff.

To evaluate the adequacy of the RCPB piping materials in light of the proposed power uprate for SSES Units 1 and 2, the NRC staff asked the licensee to respond to the RAI dated April 10, 2007 (ADAMS Accession No. ML071000141). Specifically, the staff requested that the licensee (1) identify the materials of construction for the RCPB piping/safe-ends and explain the effect of the requested power uprate on the RCPB piping/safe-end materials and its impact on the potential degradation mechanisms, (2) identify the RCPB piping/safe-end components that are susceptible to IGSCC and discuss any augmented inspection programs that have been implemented and the adequacy of the augmented inspection programs in light of the EPU, (3) identify all flawed components including overlay repaired welds that have been accepted for continued service by analytical evaluation based on ASME Code, Section XI, rules and discuss the adequacy of such analysis considering the effect of the EPU on the flaws, and (4) identify the mitigation processes being applied at SSES Units 1 and 2 to reduce the RCPB components' susceptibility to IGSCC and discuss the effect of the requested EPU on the effectiveness of these mitigation processes.

The licensee responded to the NRC staff's RAIs in letters dated May 3 (ADAMS Accession No. ML071360041), June 8 (ML071710442), and June 27, 2007 (ML071870449). In its responses, the licensee stated that SSES Units 1 and 2 were designed, fabricated, and constructed in accordance with the guidance in NUREG-0313, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping," Revision 1, issued July 1980, so most welds are IGSCC Category A welds, which are resistant to IGSCC, or Category B welds, which are stress improved by the inductive heating stress improvement (IHSI) process before operation or within 2 years of operation. However, SSES Unit 1 has 28 Category C welds (stress improved after 2 years of operation) and 2 Category E welds (weld overlay repaired welds), and SSES Unit 2 has 29 Category C welds. The IGSCC augmented inspection program at SSES Units 1 and 2 is based on NUREG-0313, Revision 2, dated January 31, 1988; BWRVIP-75-A, "BWR Vessel and Internals Project Technical Basis for Revisions to GL 88-01 Inspection Schedules"; and ASME Code, Section XI. It is well known that for IGSCC to occur, three conditions must exist—a susceptible material, tensile stresses, and an oxidizing environment. Operation at EPU conditions will result in somewhat higher pressure, temperature, and flow for some systems that constitute portions of the RCPB, but these changes will have negligible effects on the tensile stresses. Therefore, EPU operation will not affect the material's susceptibility to IGSCC. However, operation at a higher power level will result in a slightly higher oxygen generation rate as a result of radiolysis of water. As discussed later, the licensee will take additional measures to ensure that RCPB piping will continue to be mitigated in terms of IGSCC in an oxidizing environment. Because the three conditions required for IGSCC to occur are essentially unchanged for the EPU, the NRC staff considers the existing augmented inspection program for IGSCC to be adequate at the EPU operating conditions.

The licensee stated that SSES Unit 1 has two weld overlay repaired welds (RV recirculation outlet nozzle (N1B) to safe-end weld and RV recirculation inlet nozzle (N2J) to safe-end weld). The overlays were designed to the requirements of ASME Code, Section XI. The EPU operating conditions have no effect on the overlay designs because the changes in pressure, temperature, and flow rate resulting from EPU are considered insignificant at those locations and are bounded by the overlay design analysis. Thus, the two weld overlay repaired welds are considered adequate for EPU operation.

The licensee stated that it had applied several mitigation processes to SSES Units 1 and 2 to reduce the RCPB components' susceptibility to IGSCC. These include the use of IGSCC-resistant materials, application of a mechanical stress improvement process (MSIP) or IHSI process, and the implementation of HWC. The recirculation inlet safe-ends were replaced with 316L material with a carbon content of 0.02 percent before operation. All Category C and B welds underwent IHSI or MSIP. The EPU does not affect the effectiveness of MSIP or IHSI and IGSCC-resistant materials.

SSES Units 1 and 2 are currently operating with HWC. The electrochemical potential (ECP) measurements were used to monitor the effectiveness of HWC and to benchmark the secondary monitoring parameters. The secondary parameters included FW hydrogen injection rate, RWCU influent dissolved oxygen, and MSL radiation. The ECP sensors were installed as an integral part of a special local power range monitor (LPRM) assembly to monitor water from the lower plenum region of the core. This location is considered as a limiting location for the purposes of ECP measurements. All secondary parameters were benchmarked to provide correlation with measured ECP and were used to monitor the effectiveness of HWC after the burnout of the ECP probes.

The EPRI Radiolysis/ECP Model will also be used to monitor the effectiveness of hydrogen injection. Before EPU implementation, the licensee will replace the ECP probes at both units and perform a hydrogen benchmark test to determine the appropriate hydrogen injection level at the EPU operating conditions. These actions will ensure that the EPU will not affect the HWC controls used for mitigation of IGSCC.

The NRC staff finds that the licensee has taken comprehensive measures to mitigate IGSCC. These measures include the use of piping with IGSCC-resistant material, application of an MSIP or IHSI process, and implementation of HWC at SSES Units 1 and 2. The staff also finds that the licensee's intent to perform a second hydrogen benchmark test with ECP measurements provides adequate assurance that the HWC program implemented at SSES Units 1 and 2 will continue to be effective for mitigation of IGSCC under EPU operating conditions.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the susceptibility of RCPB piping 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 parameters on the integrity of RCPB piping materials. The staff further concludes that the licensee has demonstrated that the RCPB piping materials at SSES Units 1 and 2 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; Appendix G to 10 CFR Part 50; and 10 CFR 50.55a. Therefore, the NRC staff finds the proposed EPU at SSES Units 1 and 2 acceptable with respect to RCPB piping materials.

2.2 Mechanical and Civil Engineering

2.2.1 Pipe Rupture Locations and Associated Dynamic Effects

Regulatory Evaluation

The pipe-whip dynamic effects of a pipe rupture could impact SSCs important to safety at nuclear power plants. The NRC staff reviewed pipe rupture analyses to ensure that SSCs important to safety at SSES Units 1 and 2 are adequately protected from the effects of pipe ruptures. The 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 inservice inspection 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 staff's review focused on the effects that the proposed CPPU may have on items (1) through (4) above. The NRC staff's acceptance criteria are based on GDC 4 of Appendix A to 10 CFR Part 50, which requires SSCs important to safety to be designed to accommodate the dynamic effects of a postulated pipe rupture. Section 3.6.2 of the SRP contains specific review criteria.

Technical Evaluation

Attachment 4 to PLA-6076, "Power Uprate Safety Analysis Report/PUSAR/Susquehanna Steam Electric Station Units 1 and 2/Safety Analysis Report for Constant Pressure Power Uprate," issued October 2006 (Reference 1), documents the licensee's review of the CPPU effects on the postulated pipe rupture locations and associated dynamic effects for SSES Units 1 and 2. The GE report entitled "Constant Pressure Power Uprate," Licensing Topical Report NEDC-33004P-A, Class III (Proprietary) (CLTR), which maintains the current plant maximum normal operating reactor dome pressure for the CPPU, documents the licensee's approach to the CPPU. The original design-basis for the SSES Unit 1 and 2 RCPB piping postulates pipe breaks in all high-energy fluid system piping with a diameter greater than 1 inch. The licensee postulated pipe break locations for the ASME Code, Section III, Class 1, 2, and 3 piping inside and outside containment in accordance with the design stress and fatigue requirements of Section III of the ASME Code, 1971 Edition with Addenda through Winter 1972, which is the design code of record for SSES. The licensee noted that the majority of the RCPB piping systems experience no increase in pressure, temperature, flow, or mechanical loading for the CPPU, except for the MS and FW piping systems, which exhibit flow increases of about 15 percent. The licensee indicated that the CPPU does not affect seismic, hydrodynamic, or SRV discharge inertia and building displacement loads.

The licensee evaluated steamline high-energy line breaks (HELBs) in the MS, high-pressure coolant injection (HPCI), and reactor core isolation cooling (RCIC) systems for the CPPU. The licensee concluded that the CPPU has no effect on the mass and energy releases from an HELB in MS and that the CLTP analyses of the HPCI and RCIC steamline breaks are bounding for the CPPU. The licensee noted that increased MS and FW flows may lead to increased break flow rates for liquid line breaks and reevaluated the HELB mass and energy releases for the RWCU and FW systems for the CPPU. The licensee concluded that the mass and energy releases for RWCU line breaks are bounded by the conditions at the ARTS/MELLLA, and the environmental conditions that result from the CPPU mass and energy releases for FW line breaks are bounded by the MS conditions at ARTS/MELLLA. The licensee concluded that there are no new HELB locations and existing HELB evaluations of pipe-whip restraints and jet targets are not affected by the CPPU.

The licensee evaluated the LOCA containment dynamic loads for the CPPU, including pool swell, condensation oscillation (CO), and chugging loads. The analysis of record bounds the results of the pool swell analysis for the CPPU. The CO and chugging loads that the licensee developed for full-scale LOCA steam condensation tests remain bounding for the CPPU. The licensee evaluated the SRV loads for the CPPU and concluded that the parameters that affect the SRV loads remain unchanged for the CPPU.

On the basis of its review, the NRC staff finds the licensee's review of the break locations and associated dynamic effects of the LOCA and SRV loads for the CPPU to be acceptable based on the acceptance criteria documented in GDC 4 and 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 CPPU. The staff also 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 CPPU. Therefore, the staff finds the proposed CPPU acceptable with respect to the determination of 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 ASME Code, Section III, Division 1, and GDC 1, 2, 4, 14, and 15. The staff's review focused on the effects of the proposed CPPU on the design input parameters and the design-basis loads and load combinations for normal operating, upset, emergency, and faulted conditions. The 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 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, "Design Bases for Protection Against Natural Phenomena," 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, "Reactor Coolant System Design," 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. 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 contain specific review criteria.

Technical Evaluation

2.2.2.1 Nuclear Steam Supply System Piping, Components, and Supports

The RCPB piping consists of a number of safety-related piping subsystems that move fluid through the reactor and other safety systems. The RCPB piping systems that the licensee evaluated for the CPPU include the RRS; CRDS; RHR LPCI lines; CS injection lines; SLCS injection line; RPV bottom head drain line; MS piping; FW piping; the RCPB portion of the RPV head, spray, and vent lines; SRV discharge piping; and RWCU piping. The licensee's evaluation also addressed branch lines, piping supports (snubbers, hangers, and struts), nozzles, penetrations, flanges, and valves. The licensee also evaluated the thermowells and probes in the MS and FW piping systems for the CPPU.

The licensee evaluated the above RCPB piping systems in accordance with the methodology documented in GE Licensing Topical Report NEDC-33004P-A (CLTR), which maintains the current plant maximum normal operating reactor dome pressure for the CPPU. The licensee evaluated ASME Code, Section III, Class 1, 2, and 3 piping, in accordance with the design stress and fatigue requirements of Section III of the ASME Code, 1971 Edition with Addenda through Winter 1972, which is the design code of record for SSES Units 1 and 2. Pipe stress increases are scaled in proportion to pressure, temperature, and flow increases for the CPPU. In an RAI, the NRC staff asked the licensee to document the basis for the scaling factors used to calculate pipe stress increases for the CPPU. The report entitled "Susquehanna Steam Electric Station Proposed License Amendment No. 285 for Unit 1 Operating License No. NPF-14 and Proposed License Amendment No. 253 for Unit 2 Operating License No. NPF-22 Extended Power Uprate Application Re: Mechanical and Civil Engineering Technical Review Request for Additional Information Responses/PLA-6200/Docket Nos. 50-387 and 50-388" (Reference 37) documents the licensee's response to the RAIs. The staff finds the licensee's response to NRC Question 12, which documents the basis for the scaling factors used to calculate pipe stress increases for the CPPU, to be acceptable. The staff, therefore, finds the licensee's methodology acceptable.

The licensee noted that pressures, temperatures, flows, and mechanical loads for many of the RCPB piping systems do not increase for the CPPU. The CPPU does not affect seismic, hydrodynamic, SRV discharge inertia, and building displacement loads. The proprietary portion of Section 3.5.1 of PUSAR Attachment 4 documents the licensee's review of the RRS, CRDS, RHR LPCI lines, CS injection lines, SLCS injection line, and RPV bottom head drain line. The NRC staff finds the licensee's review of these RCPB piping systems for the CPPU to be acceptable.

The licensee noted that the MS and FW systems exhibit increases in flow of about 15 percent for the CPPU. The licensee evaluated the MS piping and branch lines connected to the MS headers with respect to ASME Code design stress and fatigue requirements. The licensee also evaluated piping connections to RPV nozzles, penetrations, flanges, and valves with respect to ASME Code requirements. Pipe supports (snubbers, hangers, and struts), pipe-whip restraints, and building structure anchorages were also reviewed for the CPPU.

Tables 3-6 and 3-7 of PUSAR Attachment 4 tabulate the bounding ASME Code Class 1 pipe stresses and CUFs for the MS and FW lines. The stresses and CUFs remain within ASME allowables for the CPPU. The NRC staff asked the licensee to tabulate similar data for the

RRS. Tables 7 and 8 of the appendix to Attachment 1 to PLA-6200 (Reference 37) document the licensee's response to NRC Question 13. The tabular data for Units 1 and 2 indicate that stresses and CUFs are within ASME allowables for the CLTP and CPPU.

The licensee noted that higher MS flow for the CPPU results in increased loads in the MS piping system as a result of the turbine stop valve closure transient. The turbine stop valve closure loads bound the MSIV closure loads because the turbine stop valves close more rapidly than the MSIVs. The licensee concluded that the MS piping, pipe supports, and associated components satisfy ASME Code design requirements for the increased flow resulting from the CPPU. No new postulated break locations were identified. The licensee also evaluated the FW piping and piping supports (snubbers, hangers, and struts) inside containment and piping connections to RPV nozzles, penetrations, flanges, and valves with respect to ASME Code design stress and fatigue requirements. The licensee concluded that FW piping, pipe supports, and associated components also satisfy ASME Code design requirements. The licensee did not identify any new postulated break locations.

The MS and FW systems are predicted to experience increased vibration levels because of the higher flow rates for the CPPU. Attachment 9, "Flow Induced Vibration Piping/Components Evaluation," to PLA-6076 (Reference 1), provides additional information on the plant system piping and components, including MS and FW piping and components, that might be subject to increased FIV resulting from the CPPU. Attachment 9 notes that FIV effects are proportional to the change in fluid density and the square of the fluid velocity. The vibration acceptance criteria for the licensee's power ascension program for the CPPU follows the guidance in ASME O/M-S/G Part 3, "Requirements for Preoperational and Initial Start-Up Vibration Testing of Nuclear Power Plant Piping Systems."

Section 8 of Attachment 9 to PLA-6076 notes that recorded accelerations for the recirculation/RHR piping are about 60 percent of the screening criteria, because the piping vibration levels reflect the system response to recirculation pump vane passing frequencies. The NRC staff asked the licensee to discuss the predicted vibratory response of the recirculation pump and piping for the increased system flow rate resulting from the CPPU. Attachment 1 to PLA-6200 (Reference 37) documents the licensee's response to NRC Question 14. The licensee indicated that vibration recorded at the accelerometers on the recirculation/RHR piping is almost entirely at the recirculation pump vane pass frequency. The vibration is not associated with MS or FW flow effects and their frequencies. The licensee finally noted that the increase in flow-induced vibration for the recirculation/RHR piping for the CPPU is significantly less than the 40-percent margin available. The NRC staff finds the licensee's response to Question 14 to be acceptable.

Sections 2.2.6 and 2.12 of this SE document the NRC staff's reviews of the licensee's FIV and power ascension and testing programs for the CPPU.

The licensee also confirmed that the RCPB piping materials for the CPPU are consistent with [[ ]] of the RCPB piping materials documented in the GE report "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate," Licensing Topical Report NEDC-32523P-A, Class III, issued February 2000 (ELTR2).

Based on the NRC staff's evaluation, the staff concurs with the licensee's conclusion that the designs of record for RCPB piping, supports, and associated components remain adequate for the CPPU.

2.2.2.2 Balance-of-Plant Piping, Components, and Supports

The balance-of-plant (BOP) piping consists of a number of piping subsystems that move fluid through systems outside the RCPB piping. The BOP piping that the licensee evaluated for the CPPU includes RCIC and HPCI (water segments outside the closed isolation valves); MS outside containment including turbine bypass piping, extraction steam, FW heater vents, and turbine drains; FW and condensate; RWCU outside containment; RHR outside containment; CS outside containment; HPCI outside containment; RCIC outside containment; SLCS outside containment; fuel pool cooling (FPC) and cleanup; standby gas treatment system (SGTS); service water; reactor building closed cooling water; turbine building closed cooling water; offgas; stator cooling; containment-attached piping including ECCS suction strainers; CRDS; emergency service water (ESW); circulating water; and gaseous radwaste recombiner closed cooling water system.

The licensee evaluated large- and small-bore BOP piping and supports for the CPPU in accordance with the design stress requirements of Section III of the ASME Code, 1971 Edition with Addenda through Winter 1972, or ANSI B31.1.0, "Code for Pressure Piping," 1973 Edition, which are the design codes of record for SSES Units 1 and 2. The licensee's evaluation of BOP piping and supports for the CPPU was similar to the licensee's evaluation of RCPB piping and supports, and used the original codes of record and analysis methods. Pipe stress increases are scaled in proportion to pressure, temperature, and flow increases for the CPPU. The NRC staff finds the licensee's methodology acceptable.

The licensee evaluated the DBA LOCA dynamic loads used to qualify piping and components connected to the suppression pool for the CPPU, including pool swell, vent clearing, CO, and chugging loads, and concluded that the CPPU does not affect piping, vent penetrations, and valves connected to the suppression pool. The licensee noted that the CPPU does not affect seismic, hydrodynamic, SRV discharge inertia, and building displacement loads.

The proprietary portion of Section 3.5.2 of PUSAR Attachment 4 documents the licensee's review of the RCIC and HPCI systems (water segments outside the closed isolation valves). The NRC staff finds the licensee's review of these BOP piping systems for the CPPU to be acceptable.

The licensee evaluated the remaining BOP piping and supports for increases in pressure, temperature, and flow for the CPPU. The licensee noted that the design-basis pressures, temperatures, and flows for the majority of the BOP piping systems bound CPPU values.

Table 3-9 of PUSAR Attachment 4 tabulates bounding pipe stress and pipe support load increases for the FW, condensate, and extraction steam systems and FW heater drains and vents for the CPPU. The maximum pipe stresses increase by 4–20 percent because of pressure, and the maximum pipe support loads increase by 3 percent because of thermal expansion. The licensee's evaluation of the piping segments with the higher pipe stresses and pipe support loads documented in Table 3-9 determined that the piping and supports continue to meet the design requirements of the plant codes of record for the CPPU. The evaluation identified no new postulated break locations.

Table 3-10 of PUSAR Attachment 4 tabulates bounding pipe stress and pipe support load increases for the MS system, including the turbine bypass and RFPT systems, for the CPPU. The maximum pipe stresses increase by 20 percent and the maximum pipe support loads increase by 45 percent as the result of fluid transient loads. The licensee noted that the increased flow in the MS system for the CPPU results in increased fluid transient loads from the turbine stop valve closure transient. The turbine stop valve closure loads bound the MSIV closure loads because the turbine stop valves close more rapidly than the MSIVs. The licensee indicated that these increased fluid transient loads require some modifications to piping, pipe supports, and RFPT nozzles.

Table 3-11 of PUSAR Attachment 4 lists the piping segments that are being modified to reduce piping stresses to below code-allowable stresses. Pipe stresses for a segment of the 8-inch steam seal evaporator piping for SSES Unit 2 and a segment of the RFPT piping for SSES Units 1 and 2 exceed those allowed by code. No new postulated break locations were identified. Table 3-12 lists 12 snubbers and 1 guide in MS and steam seal evaporator piping installed in SSES Unit 1 that require modification to reduce pipe support loads below code-allowable support loads. Table 3-13 lists 10 snubbers and 3 anchors in MS and steam seal evaporator piping installed in SSES Unit 2 that require modification to reduce pipe support loads below code-allowable support loads. Table 3-14 lists three HP steam to RFPT nozzles in SSES Unit 1 and two RFPT nozzles in SSES Unit 2 that currently exceed allowable nozzle interaction loads and require the additional snubber restraints to reduce the nozzle loads below the allowable interaction loads. In response to RAIs (NRC Questions 16, 17, and 19), the licensee indicated that the CPPU evaluations documented in Tables 3-10 through 3-14 of PUSAR Attachment 4 used very conservative scaling factors to identify the components, piping, and supports that might exceed allowable stresses or loads for the CPPU. The licensee generated more detailed bounding turbine stop valve closure loads to generate new forcing functions for the piping inside and outside containment for the CPPU and applied these new forcing functions to the piping stress calculations. The revised stress calculations demonstrate that only two Unit 1 and one Unit 2 MS and steam seal snubbers require modification for the CPPU.

The licensee will replace the two Unit 1 snubbers during the Unit 1 15th refueling outage in spring 2008. It replaced the one Unit 2 snubber during the Unit 2 13th refueling outage completed in spring 2007. The licensee also noted that the installation of four new snubbers on the Unit 2 HP steam piping to the reactor feedwater pump (RFP) turbines installed during the Unit 2 13th refueling outage reduces the loads on the Unit 2 RFP turbine nozzles to within existing vendor allowances. The licensee will install additional snubbers on the Unit 1 HP steam piping to the RFPTs during the Unit 1 15th refueling outage to reduce the Unit 1 RFPT nozzles to within existing vendor allowances. Tables 1 through 6 of the appendix to Attachment 1 to PLA-6200 (Reference 37) summarize the results of the licensee's revised analyses.

In NRC Question 18, the staff asked the licensee to document the basis for the allowable RFPT nozzle forces and moments and the interaction formula documented in Table 3-14 of PUSAR Attachment 4. The licensee indicated that the RFPT nozzle load allowables are the original values GE supplied during the initial design of SSES Units 1 and 2. Attachment 1 to PLA-6200 (Reference 37) documents the licensee's responses to NRC Questions 16, 17, 18, and 19. The NRC staff finds the licensee's responses to Questions 16, 17, 18, and 19 to be acceptable.

The BOP piping systems that experience higher flow rates for the CPPU are also predicted to experience increased vibration levels. Attachment 9 to PLA-6076 provides additional information on the plant system piping and components that might be subject to increased FIV as a result of the CPPU. Table 2 of Attachment 9 lists changes in flow rates of about 15 percent and potential increases in FIV of about 32 percent for the MS and FW condensate, extraction steam, and FW heater drains systems. Attachment 9 notes that FIV effects are proportional to the change in fluid density and the square of the fluid velocity. The vibration acceptance criteria for the licensee's power ascension program for the CPPU follow the guidance in ASME O/M-S/G, Part 3.

Sections 2.2.6 and 2.12 of this SE document the NRC staff's reviews of the licensee's FIV and power ascension and testing programs for CPPU.

Section 3.7 of PUSAR Attachment 4 documents the licensee's review of the MS line flow restrictors. The staff finds the licensee's review of the MSL flow restrictors for the CPPU to be acceptable.

Based on its review as summarized above, the NRC staff concludes that the licensee has adequately evaluated BOP piping, pipe supports, and associated components for the effects of the proposed CPPU.

2.2.2.3 Reactor Vessel and Supports

The licensee evaluated the RPV structures and support components for the CPPU for the design, normal, upset, emergency, and faulted conditions in accordance with the design stress and fatigue requirements of Section III of the ASME Code, 1968 Edition with Addenda through Summer 1970, which is the design code of record for SSES Units 1 and 2. The licensee also used the 1971 Edition of the ASME Code for simplified elastic-plastic analysis and used several ASME Code cases for the RPV materials of construction. For components modified or reevaluated since original construction, including the FW nozzle (N-4), control rod drive-hydraulic system return (CRD-HSR) nozzle cap, recirculation inlet nozzle (N-2), in-core housing penetration, and intermediate range/source range/local power range monitor (IRM/SRM/LPRM) and dry tube, the licensee used the ASME Code editions and addenda documented in the component stress analyses. The licensee noted that the IRM/SRM/LPRM and dry tube are considered life-limited components and are replaced as required.

The licensee noted that it did not specifically evaluate RPV components with [[

]], in accordance with the methodology documented in Appendix I to the GE report "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," Licensing Topical Report NEDC-32424P-A, Class III (Proprietary) dated February 1999 (ELTR1). The GE report NEDC-33004P-A (CLTR), which maintains the current plant maximum normal operating reactor dome pressure for the CPPU, documents the licensee's approach to the CPPU. The NRC staff finds the licensee's methodology acceptable.

RPV components that the licensee determined did not require reevaluation for the CPPU include the recirculation outlet nozzle (N-1), recirculation inlet nozzle (N-2), core spray nozzle (nozzle/shell junction, N-5), top head spray and spare nozzles (N-6), vent nozzle (N-7), jet pump instrumentation nozzle (N-8), CRD-HSR nozzle (N-9), instrumentation nozzles (N-11, N-12, N-16), seal leak detection nozzle (N-13), drain nozzle (N-15), control rod drive (CRD) penetration stub tube, shroud support, refueling bellows support, and in-core housing penetration components. These RPV components have [[

]] The licensee noted that these original components were previously evaluated using original licensed thermal power (OLTP) design conditions, which bound the CPPU operating conditions.

Table 3-1 of PUSAR Attachment 4 lists the RPV components that the licensee evaluated for CPPU. These components have CUFs greater than 0.5 and include the steam outlet nozzle (N-3), the FW nozzle (safe end, nozzle shell junction, N-4), core spray nozzle (safe end, N-5), core delta P and liquid control nozzle (N-10), stabilizer bracket, support skirt (Units 1 and 2), and the main closure region (stud, head flange). Except for a slight increase in the stress for the steam outlet nozzle (N-3), the stresses and CUFs for the listed components remain unchanged from current licensed thermal power (CLTP) to CPPU conditions and continue to meet ASME design stress and fatigue requirements.

Based on its review of the licensee's evaluation of the RPV structures and support components for the CPPU, the NRC staff finds that maximum stresses and fatigue usage factors are within code-allowable limits. The staff also concurs with the licensee's conclusion that the RPV structures and support components will continue to maintain their structural integrity for CPPU conditions.

2.2.2.4 Control Rod Drive Mechanism

Section 3.3.2 of PUSAR Attachment 4 documents the licensee's evaluation of the CRD mechanism for the CPPU. The licensee stated that a qualitative or quantitative assessment was performed for the RPV internals, including the CRD mechanism, consistent with the existing design basis and the changes in loads for CPPU. [[

]]

Based on its review of the licensee's evaluation of the CRD mechanism, the NRC staff finds that all subject stresses are within code-allowable limits or remain bounded by the original design basis loads. The NRC staff also concurs with the licensee's conclusion that the CRD mechanism is structurally qualified for the CPPU.

2.2.2.5 Recirculation Pumps and Supports

As documented in Section 3.4.1 of PUSAR Attachment 4, the recirculation system drive flow is not significantly increased (less than 2.3 percent) for the CPPU. Sections 3.4.1 and 3.5.1 of PUSAR Attachment 4 document the licensee's proprietary review of the RRS for the CPPU. The NRC staff asked the licensee to augment PUSAR Attachment 4 to discuss (1) the code of record for the recirculation pumps and supports, (2) the design-basis loads for the recirculation pumps and supports, and any changes to these loads, including flow rate, for the CPPU, (3) the adequacy of the original stress and fatigue analyses and tests to qualify the recirculation pumps and supports, or any changes to these analyses and tests, for the CPPU, and (4) the potential for higher pump vibration levels resulting from greater flow rate for the CPPU.

Attachment 1 to PLA-6200 (Reference 37) documents the licensee's response to NRC Question 15. With respect to item 1, the licensee indicated that the code of record for the recirculation pumps and supports is the ASME Code, Section III. As described in Section 3.9.3.1.6 of the SSES Unit 1 and 2 FSAR, the licensee used the ASME Code, Section VIII, Division 1, 1971 Edition with latest addenda, as a guide to size the thickness of pressure-retaining parts and pressure-retaining bolting. In response to item 2, the licensee noted that the design-basis loads for the recirculation pumps and supports are the NSSS loads listed in Table 3.9-2 of the SSES Unit 1 and 2 FSAR. As stated in Section 3.5.1 of PUSAR Attachment 4, the operating-basis earthquake (OBE) and safe-shutdown earthquake (SSE) and the hydrodynamic loads are not changed for the CPPU. In response to item 3, the licensee noted that the analyses and tests described in the SSES Unit 1 and 2 FSAR are adequate to qualify the recirculation pumps and supports for the CPPU. Tables 3.9-2e and 3.9-2e.1 of the SSES Unit 1 and 2 FSAR summarize the results of the CLTP analyses for the recirculation pumps. The pump support analyses are included with the piping qualification calculations. In the proprietary portion of its response to item 3, the licensee noted that these analyses are applicable for the CPPU. In response to item 4, the licensee noted that the vibration of the reactor recirculation pump is not expected to change significantly for the CPPU, since the pump operating speed will remain within the range of speeds qualified for CLTP. Based on its review, the NRC staff concurs with the licensee's conclusion that the current design basis of the reactor recirculation pumps and supports remains adequate for the CPPU.

Conclusion

The NRC staff has reviewed the licensee's evaluations related to the structural integrity of pressure-retaining components and their supports. For the reasons given above, the staff concludes that the licensee has adequately addressed the effects of the proposed CPPU on these components and their supports. Based on the above, the 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 CPPU. Therefore, the NRC staff finds the proposed CPPU 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

RPV 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 CPPU 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 LOCAs, and the identification of design transient occurrences. The staff's review covered (1) the analyses of FIV for safety-related and nonsafety-related reactor internal components and (2) the analytical methodologies, assumptions, ASME Code editions, and computer programs used for these analyses. The review also included a comparison of the resulting stresses and CUFs against the corresponding limits allowed by the ASME Code.

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, “Reactor Design,” 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 AOOs. 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 contain specific review criteria.

<u>Technical Evaluation</u>

The RPV internals consist of the core support structure (CSS) and noncore support structure components. The licensee noted that, except for the CRD mechanism, the RPV internals are not certified to the ASME Code. The licensee prepared design-basis analyses for the RPV internals using ASME Code criteria as guidelines and used the same guidelines to reevaluate the RPV internals for the normal, upset, emergency, and faulted conditions for the CPPU. The licensee evaluated the RPV internals for the effects of [[

]]

In addition to the steam dryer (discussed later in this SE), the licensee evaluated the shroud, shroud support, core plate, top guide, CRD housing, control rod guide tube, orificed fuel support, fuel channel, FW sparger, jet pump assembly, core spray line, core spray sparger, access hole cover, shroud head and steam separator assembly, including the shroud head bolts, in-core housing and guide tube, vessel head cooling spray nozzle, jet pump instrument penetration seal, core differential pressure and liquid control line, and the CRD mechanism for the CPPU. Table 3-8 of PUSAR Attachment 4 lists the governing stresses/critical parameters for the RPV internals. All stresses/critical parameters are within allowable limits. Note 6 of Table 3-8 of PUSAR Attachment 4 states, “In order to reduce conservatism, credit was taken for the seismic pins to resist lateral loads, which results in the elimination of bending stress in the shroud head bolts.” The NRC staff asked the licensee to describe the evaluation of the seismic pins for the CPPU. Attachment 1 to PLA-6200 (Reference 37) documents the licensee’s response to NRC Question 20. The licensee noted that the seismic pins are mounted vertically on the shroud flange and fit into close-fitting blind holes in the shroud head flange. The pins do not prevent lifting of the shroud head but provide redundant capacity to the shroud head assembly to prevent sliding. The seismic pins are able to support the entire horizontal seismic load in shear, and the stresses in the seismic pins meet the ASME Code allowable limits for all operating levels.

Section 3.4.2 of PUSAR Attachment 4 indicates that the steam separator is “significantly affected by CPPU conditions.” The NRC staff asked the licensee to summarize its evaluation of the steam separators for the CPPU. Attachment 1 to PLA-6200 documents the licensee’s response to NRC Question 21. The licensee noted that the steam separators are nonsafety-related components. The GE Model 67PL fixed axial flow type steam separators are made of stainless steel and have no moving parts. The steam-water mixture rising through the standpipe in each separator impinges on the vanes, which creates a vortex that separates the water from the steam in each of three stages. The steam leaves at the top of the separator and passes into the wet steam plenum below the dryer. The separated water exits from the lower end of each stage of the separator and enters the pool that surrounds the standpipes to join the downcomer annulus flow. At CPPU conditions, the higher steam output from the core increases the steamflow velocity through the separators by about 13 percent. This increase in steamflow velocity may increase the FIV of the steam separators. Extensive flow vibration tests were conducted on the steam separators to investigate potential FIV issues. The licensee's response to NRC Question 21 documents the evaluation of the results of the tests conducted on the steam separators. The licensee also noted that no structural problems resulting from temperature or flow effects have been identified for the steam separators. The licensee, therefore, concluded that the steam separators installed in SSES Units 1 and 2 will remain structurally adequate for the CPPU. The NRC staff finds the licensee's response to NRC Question 21 to be acceptable.

With respect to the effects of RIPD for the CPPU, Tables 3-2 through 3-5 of PUSAR Attachment 4 list the licensee's evaluations of the shroud support ring and lower shroud, core plate and guide tube, upper shroud, shroud head, shroud head to water level (loss across the separators), shroud head to water level (loss between the inside of the shroud to the exit of the separators), top guide, and fuel channel wall. The licensee noted that the GE14 fuel analysis bounds all RIPDs, except for the fuel channel wall RIPDs. The licensee indicated that the fuel channel wall RIPDs listed in Tables 3-2 through 3-5 are calculated for the ATRIUM-10 fuel pressure drop and are acceptable for the CPPU except for the 80-mil fuel channels. The 80-mil fuel channels will be discharged. The licensee will operate the 80-mil fuel channels before ascension to full CPPU power in core locations that maintain RIPDs within the pressure load limit. The proprietary portion of Section 3.3.1 of PUSAR Attachment 4 documents the licensee's disposition of the jet pump sensing lines, dryer/separator guide rods, and in-core guide tube braces for the effects of RIPD for the CPPU. The NRC staff finds the licensee's review of these minor RPV internal components for the CPPU to be acceptable.

With respect to the effects of FIV for the CPPU, the licensee evaluated the RPV internals using a reactor operational power of 3952 MWt and 108 percent of rated core flow. The licensee indicated that the maximum drive flow increases 2.2 percent from the CLTP to the CPPU, which may increase the vibration levels of the RPV internals. The licensee's evaluation of FIV is based on vibration data obtained during startup testing of Browns Ferry 1 (the prototype plant). For components not instrumented in the prototype plant, the evaluation relied on vibration data obtained from startup testing at similar plants, or acquired outside the RPV, or by analysis. The licensee compared estimated vibration levels for the CPPU with the GE criterion of 10,000 pounds per square inch (psi) peak stress intensity. The GE stress criterion is less than the ASME Code criterion of 13,600 psi and is within the endurance limit for stainless steel. No fatigue usage is accumulated during normal operation. The licensee also absolute-summed the maximum amplitudes of the vibratory modes. The NRC staff considers the licensee's methodology to be acceptable.

The licensee evaluated the shroud, shroud head and moisture separator, jet pumps, FW sparger, and jet pump sensing lines for the effects of FIV for the CPPU. The licensee additionally evaluated RPV internal components in the steamflow and FW flowpaths. Based on its evaluation, the licensee concluded that vibrations of the RPV internal components are within the GE acceptance criterion. The proprietary portion of Section 3.4.2 of PUSAR Attachment 4 documents the licensee's disposition of the RPV in-core guide tubes and control rod guide tubes. The NRC staff finds the licensee's review of these RPV internal components for the CPPU to be acceptable.

The licensee noted that a separate evaluation is being performed for the steam dryer for the CPPU. Section 2.2.6 of this SE documents the NRC staff's review of the licensee's qualification of the steam dryer for the CPPU.

Conclusion

The NRC staff has reviewed the licensee's evaluations related to the structural integrity of reactor internals and core supports (a later section of this SE addresses the steam dryer). The staff concludes that the licensee has adequately addressed the effects of the proposed CPPU on the reactor internals and core supports. The 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 and GDC 1, 2, 4, and 10 following implementation of the proposed CPPU. Therefore, the NRC staff finds the proposed CPPU 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 of the EPU LAR for SSES Units 1 and 2 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, as applicable. The staff's review focused on the effects of the proposed uprate on the required functional performance of the safety-related valves and pumps. The review also covered potential impacts that the uprate might have on the licensee's programs related to GL 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," dated June 28, 1989; GL 96-05, "Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves," dated September 18, 1996; and GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Valves," dated August 17, 1995. The staff also evaluated the licensee's consideration of lessons learned from the motor-operated valve (MOV) program and the application of those lessons to other safety-related power-operated valves.

The acceptance criteria for the NRC staff review are based on the NRC regulations in 10 CFR Part 50, including (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 37, "Testing of Emergency Core Cooling System," GDC 40, "Testing of Containment Heat Removal System," GDC 43, "Testing of Containment Atmosphere Cleanup Systems," and GDC 46, "Testing of Cooling Water System," insofar as they require that these systems be designed to permit appropriate periodic testing to ensure the leak-tight integrity and performance of their active components, (3) GDC 54, "Systems Penetrating Containment," insofar as it requires that piping systems penetrating containment be designed with the capability to allow periodic testing of 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 specified inservice testing (IST) program requirements. SRP Sections 3.9.3 and 3.9.6 and other guidance provided in Matrix 2 of RS-001 contain specific review criteria.

Technical Evaluation

On October 11, 2006, the licensee of SSES Units 1 and 2 submitted a proposed EPU license amendment that would increase the maximum authorized power level for each unit from 3489 MWt to 3952 MWt, an increase of approximately 13-percent thermal power from CLTP. In an RAI dated April 18, 2007 (ADAMS Accession No. ML071060135), the NRC staff asked the licensee to discuss the plans to implement the IST program for SSES that incorporates appropriate changes in light of applicable EPU operating conditions. In its RAI response dated June 1, 2007 (ML071620311), the licensee discussed and provided examples of its evaluation of the impact of EPU conditions on the performance of safety-related pumps and valves. [[

]] The licensee is making various modifications to the ESW system and the SSES Unit 1 and 2 UHS and will change the IST program in response to those modifications. [[

]] Safety-related electrical loads are not changed for power uprate conditions, and thus no IST program changes are necessary for the power supplies. The licensee will upgrade pipe supports on the main and FW systems and will address changes to the snubber inspection and testing program as part of the engineering change process.

In Section 4.1.4, GL 89-10 Program, of Attachment 4 to its submittal dated October 11, 2006, the licensee stated that it had reviewed process parameters of temperature, pressure, and flow for MOVs and identified increases in design differential pressure as the result of operation at CPPU conditions for some MOVs. The licensee also stated that operation at CPPU conditions increases postaccident temperatures in rooms where some MOVs are located, which potentially reduces the actuator output torque. Based on its review, the licensee stated that the GL 89-10 MOVs are capable of performing their design-basis safety functions at CPPU conditions. In its RAI, the NRC staff asked the licensee to discuss with examples its evaluation of safety-related MOVs within the programs established in response to GL 89-10 and GL 96-05 at SSES for the potential impact from EPU operation, including the effect of increased process flows on operating requirements and increased ambient temperature on motor output.

In its RAI response dated June 1, 2007, the licensee reported that it had reviewed the MOV capability calculations for the impact of process parameter changes for the power uprate and determined that all MOVs have a positive available margin based on the evaluation. For example, the power uprate will result in a postulated increase in the peak drywell pressure after a reactor recirculation (RR) line break from 44.6 psig to 48.6 psig. This increase in peak drywell pressure was evaluated for the reduction in total available margin for the applicable MOVs. Increased flow rates for power uprate operation in the MS, RR, and ESW systems do not impact the calculated load for the gate and globe valves, while the flow increase in the ESW system of less than 1 percent is negligible for the butterfly valves in the system. The peak temperature in the drywell is postulated to increase from 320 °F to 337 °F after an MS line break inside containment at CPPU conditions but drops to less than 300 °F at 5 seconds following the break.

The small temperature increase and its short duration will not adversely impact the internal components of the applicable MOVs.

In Section 4.1.4 of the PUSAR, the licensee stated that it reviewed MOVs used as containment or HELB isolation valves, and air-operated valves (AOVs) used as containment isolation valves, for the effects of operation at CPPU conditions, including thermal binding and pressure locking (GL 95-07). The NRC staff provided an SE on the licensee's response to GL 95-07 for SSES Units 1 and 2 in a letter dated November 1, 1999. In its RAI, the staff asked the licensee to discuss with examples its evaluation of safety-related, power-operated gate valves regarding the potential for pressure locking or thermal binding resulting from EPU operation at SSES. In its RAI response dated June 1, 2007, the licensee reported that the CPPU does not affect the corrective actions implemented at SSES Units 1 and 2 in response to GL 95-07. Valves originally found not susceptible to pressure locking or thermal binding remain not susceptible because of design, application, or procedural guidance.

In Section 4.1.4 of the PUSAR, the licensee stated that it reviewed the process parameters of temperature, pressure, and flow for AOVs and identified increases in design differential pressure resulting from operation at CPPU conditions for some AOVs. Based on its review, the licensee stated that all AOVs with active safety-related or safety-significant functions are capable of performing their design-basis safety functions at CPPU conditions. In its RAI, the NRC staff requested that the licensee discuss with examples its evaluation of safety-related AOVs and solenoid-operated valves, as applicable, for potential impact from EPU operation at SSES. In its RAI response dated June 1, 2007, the licensee reported on the evaluation of AOVs as a result of process parameter changes for the CPPU. The licensee determined that all AOVs have a positive available margin for the ability to perform their safety function. For example, the containment vent and purge valves were assessed for the drywell pressure increase from 44.6 to 48.6 psig. As a result of the postulated increase in peak drywell pressure after a DBA LOCA, the licensee determined that the four-way solenoid valve on the inboard MSIVs might not reposition when activated. The licensee replaced these four-way solenoid valves for both SSES units with valves that require less differential pressure to reposition.

The increased flow rates in the FW, MS, and condensate systems do not impact the calculated differential pressure load for the valves (gate and globe design) in these systems.

In Section 3.8 of Attachment 4 to its submittal dated October 11, 2006, the licensee discussed the evaluation of MSIVs for EPU conditions. In that section, the licensee indicated that the MSIVs must be able to close within a specified time range at all design and operating conditions. The increase in flow rate for EPU operation will assist in MSIV closure and result in a slightly faster MSIV closure time. The licensee also referenced Section 4.7 of NEDC 32523P-A (ELTR-2) in its description of the evaluation of MSIVs for EPU conditions. In an SE of NEDC-32523P-A, dated September 14, 1998, the NRC staff accepted the GE evaluation of MSIV capability to operate acceptably at EPU flow conditions.

Conclusion

As discussed in this SE, the NRC staff has reviewed the licensee's assessments related to the functional performance of safety-related valves and pumps for SSES in support of the EPU LAR. The staff concludes that the licensee has adequately addressed the effects of the proposed EPU on safety-related pumps and valves. The staff further concludes that the licensee has adequately evaluated the effects of the proposed EPU on its valve programs related to GL 89-10, GL 96-05, and GL 95-07 and has applied the lessons learned from those programs to other safety-related, power-operated valves. Based on its review, the staff concludes that the licensee has demonstrated that safety-related valves and pumps will continue to meet the requirements of GDC 1, 37, 40, 43, 46, and 54, and 10 CFR 50.55a(f) following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable for SSES with respect to safety-related valves and pumps.

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. This section also covers equipment associated with systems essential to preventing significant releases of radioactive materials to the environment. The NRC staff's review focused on the effects of the proposed CPPU on the qualification of the equipment to withstand seismic events and the dynamic effects associated with pipe-whip and jet impingement forces. A CPPU does not affect the primary input motions resulting from the SSE. The NRC's acceptance criteria are based on 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, "Quality of Reactor Coolant Pressure Boundary," 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) Appendix A to 10 CFR Part 100, 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) Appendix B to 10 CFR Part 50, which sets quality assurance requirements for safety-related equipment. SRP Section 3.10 contains specific review criteria.

Technical Evaluation

The licensee evaluated safety-related mechanical equipment subject to increased nozzle loads and component support loads as a result of increased temperatures, flows, or pressures for the CPPU. The licensee noted that the CPPU does not result in new HELB locations or affect existing HELB evaluations of pipe-whip restraints and jet targets. The licensee also noted that the CPPU does not affect seismic, hydrodynamic, and SRV discharge inertia and building displacement loads. The NRC staff notes that the seismic design basis for SSES Units 1 and 2 remains unchanged for the CPPU.

The staff asked the licensee to confirm that reviews of component nozzle loads and support loads for the CPPU addressed the upset, emergency, and faulted design conditions, which incorporate OBE or SSE loads. Attachment 1 to PLA-6200 (Reference 37) documents the licensee's response to NRC Question 22. Sections 3 and 4.1 of PUSAR Attachment 4 describe the effects of increased fluid-induced loads on safety-related components.

The CPPU does not significantly affect safety-related pumps and heat exchangers, but it does affect safety-related components on or attached to the MS piping, such as the RPV and MSIVs. The licensee indicated that the analyses performed for the increased turbine stop valve closure loads for the CPPU address the upset, emergency, and faulted design conditions, which incorporate the OBE or SSE loads defined for CLTP.

The licensee performed a seismic margins assessment (SMA) following the guidance of EPRI Report No. NP-6041, "A Methodology for Assessment of Nuclear Power Plant Seismic Margin," Revision 1, issued August 1991. The licensee documented the results of the seismic review in the PPL document entitled "Susquehanna Steam Electric Station Response to Audit Issues on IPEEE Submittal Units 1 and 2" (PLA-4983), issued October 1998. Based on its actions to correct the seismic issues that the SMA had identified, the licensee concluded that the CPPU has little or no impact on the seismic qualification of SSCs. The NRC staff asked the licensee to briefly discuss the SMA performed and to summarize any open seismic items from the SMA.

Attachment 1 to PLA-6200 documents the licensee's response to NRC Question 23. The licensee indicated that it performed the SSES SMA in 1993 and 1994 according to the methodology presented in EPRI NP-6041. The SSES was classified as a "focused scope" in GL 88-20, Supplement 4, "Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities," dated June 28, 1991. SSES was evaluated for a seismic margins earthquake (SME) level of 0.30 acceleration of gravity (g) of peak ground acceleration (PGA), which is three times greater than the 0.10 g design-basis SSE maximum ground acceleration level. The SMA assessed appropriate structures, systems, and equipment to demonstrate a high confidence of low probability of failure (HCLPF) with respect to the 0.30 g SME level. To determine the scope of the SMA, a primary and an alternate safe shutdown path for achieving hot shutdown were established. From the paths identified to achieve hot shutdown, the safe-shutdown equipment list (SSEL) was developed. This equipment was a subset of all "Q" equipment, which had been seismically qualified in accordance with Institute of Electrical and Electronics Engineers Standard 344 before startup. Most of the SMA involved the assessment of the equipment on the SSEL and included a detailed review of low ruggedness relays.

The assessment also addressed distribution systems (piping, electrical raceways, and heating, ventilation, and air conditioning (HVAC) systems) and safety-related structures. The equipment on the SSEL was evaluated for functional capability and anchorage adequacy at the 0.30-g SME level. In addition, accessible equipment was walked down to (1) review equipment configuration for vulnerabilities associated with actual failure modes from an earthquake experience data bank, (2) identify installed anchorage arrangement, and (3) note any seismic interaction issues that could affect the performance of the equipment during an earthquake. The structures, systems, and equipment (with a few exceptions) and installed low ruggedness relays were found to be acceptable for the SME. The exceptions noted involved seismic interaction concerns identified during the equipment walkdowns. Examples included unrestrained breaker hoists mounted on top of load centers, adjacent panels in proximity that were not fastened together, and unrestrained items in proximity to safety-related equipment that could have rolled or toppled into vital equipment during a seismic event. Some equipment was also noted to have missing and/or broken hardware. The licensee corrected all of the identified deficiencies as part of the SSES Unit 1 and 2 modification or corrective action programs. The licensee noted that there are no open seismic issues associated with the SMA performed in 1993 and 1994.

Based on the foregoing review, the NRC staff concludes that the CPPU does not affect the original seismic and dynamic qualification of safety-related mechanical and electrical equipment for SSES Units 1 and 2.

Conclusion

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

2.2.6 Additional Review Area—Potential Adverse Flow Effects

Regulatory Evaluation

Plant operation at EPU conditions can result in adverse flow effects on the MS, FW, and condensate systems and their components, including the steam dryer in BWR nuclear power plants, because of increased system flow and FIV. Some plant components, such as the steam dryer, do not perform a safety function but must retain their structural integrity to avoid the generation of loose parts that might adversely impact the capability of other plant equipment to perform its safety functions. The NRC staff reviewed the licensee's consideration of potential adverse flow effects of the proposed EPU at SSES Units 1 and 2, including consideration of the design input parameters and the design-basis loads and load combinations for the SSES steam dryer for normal operation, upset, emergency, and faulted conditions. The staff's review covered the analytical methodologies, assumptions, and computer programs used in the evaluation of the SSES steam dryer. The review also included a comparison of the resulting stresses against applicable limits.

The NRC staff also reviewed the licensee's evaluation of other reactor, MS, FW, and condensate system components at SSES Units 1 and 2 for potential susceptibility to adverse flow effects from EPU operation. The NRC's acceptance criteria are based on (1) GDC 1, insofar as it requires that systems and components essential to the prevention of accidents that could affect the public health and safety or to the mitigation of their consequences be designed, fabricated, erected, 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 systems and components essential to the prevention of accidents that could affect the public health and safety or to the mitigation of their consequences be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions, and (3) GDC 40 and 42, "Inspection of Containment Atmosphere Cleanup Systems," insofar as they require that protection be provided for engineered safety features (ESFs) against the dynamic effects and missiles that might result from plant equipment failures, as well as the effects of a LOCA. SRP Sections 3.9.1, 3.9.2, 3.9.3, and 3.9.5 contain specific review criteria.

Technical Evaluation

2.2.6.1 Steam Dryer

The NRC staff reviewed the licensee's consideration of potential adverse flow effects of the proposed EPU on the steam dryer in the two SSES units, including consideration of the design input parameters and the design-basis loads and load combinations for the SSES steam dryer for normal operation, upset, emergency, and faulted conditions. The NRC staff's review covered the analytical methodologies, assumptions, and computer programs used in the evaluation of the SSES steam dryer. The review also included a comparison of the resulting stresses against applicable ASME Code limits.

Attachment 10 to PPL letter PLA-6076 describes the SSES steam dryer design and defines the PPL approach to overall dryer stress assessment. This attachment summarizes the information provided in the appendices (scale model assessments of projected dryer loading at CPPU conditions, acoustic circuit models, finite-element stress analyses) and includes a bias error and uncertainty assessment. The NRC provided comments to PPL regarding the lack of technical justification for determining SSES steam dryer pressure loads and other technical issues in a letter dated November 2, 2006 (ADAMS Accession No. ML063250092). In its responses dated December 4, 2006 (ML063460354) and April 27, 2007 (Reference 36), PPL explained that new dryers are to be installed in both SSES units and described the new dryers. In the replacement dryer, [[

]]

PPL computed the estimated dryer stresses at EPU conditions, including weld factors, the stress underprediction factor (SUPF), and a scale factor to estimate loads at EPU conditions (120 percent OLTP). PPL will install strain gauges on the new dryer in Unit 1 at locations of high stress. PPL explained that it accounted for acoustic circuit monitor (ACM) dryer load underpredictions by using the SUPF, which addresses the end-to-end bias error of the stress analysis procedure. PPL stated that the finite-element model (FEM) uncertainty is considered by performing several analyses with different time shifting [[
]], and that the worst-case finite-element uncertainty is compared to the stress margin at nominal conditions. PPL will assess frequency-dependent bias and uncertainties based on instrumented dryer measurements. PPL will monitor how loads at specific frequencies increase during power ascension to confirm the acceptability of the SUPF.

2.2.6.1.1 SSES Steam Dryer Experience

SSES is a BWR 4 reactor having a steam dryer with a curved hood design, which is similar to the Hope Creek and Hatch Unit 2 steam dryers. The MSL flow velocity for SSES is 128 feet per second (fps) at OLTP and 136 fps at CLTP (about 106-percent OLTP) and is projected to be 153 fps at the CPPU (about 120-percent OLTP). The predicted SSES velocity at the CPPU is smaller than OLTP velocities at some BWR 3 plants, which have experienced cracking of their steam dryers.

During the first refueling outage for SSES Unit 1, a fatigue failure was identified in one of the second bank hoods at an end plate. The hood was repaired with a 3/16-inches thick and 2-inch wide strip welded over the vertical length of the end of the hood. After repairs were completed, the SSES steam dryer was instrumented in 1985 with strain gauges and accelerometers and then returned to service. The measurements provided by the instrumented dryer showed a reduction in stress of approximately an order of magnitude at the location of repair. Subsequently, the other similar welds were modified to match the repair. This repair was also applied to the SSES Unit 2 dryer as well as to other curved hood dryers throughout the BWR fleet. The instrumented dryer provided data that are used for benchmarking the analyses performed to assess structural integrity of SSES steam dryers under EPU conditions.

PPL has inspected the SSES steam dryers in accordance with the guidelines in BWRVIP-139, "BWR Vessel and Internals Project Steam Dryer Inspection and Flaw Evaluation Guidelines." During the inspection of Unit 2 in 2005, PPL identified a possible fatigue crack in the middle of a dryer bank thin end plate weld. In 2006, PPL identified a crack in the Unit 1 steam dryer at a similar location. In both cases, weld repair was performed before the dryers returned to service. [[

]]

2.2.6.1.2 <u>Scale Model Testing</u>

PPL used two scale model testing (SMT) methods to model acoustic resonance in the steamlines under EPU conditions—the Continuum Dynamics Inc. (CDI) SMT and the GE SMT. PPL indicated that the CDI SMT shows that no flow-excited resonances in the SRVs are expected at CPPU conditions and that 15-hertz (Hz) pressure fluctuations resulting from the interaction of RPV flow and the dead legs in the A and D MSLs should not increase between CLTP and CPPU conditions. PPL also indicated that the GE SMT test results show no increase in dryer loading between CLTP and CPPU conditions. Based on these SMT results, PPL applied a dryer loading increase proportional to the square of MSL velocity.

In Attachment 1 to PPL letter PLA-6242 dated July 31, 2007 (Reference 38), PPL clarified its use of the SMT results. It stated that it is using the SMT results to provide supporting evidence that (1) SRV acoustic resonances are not expected in the EPU operating range for SSES, and (2) the low-frequency pressure loads are expected to increase proportionally to the square of the steamflow velocity at power levels above CLTP. The NRC staff finds this clarification acceptable.

CDI Scale Model Testing

CDI Report 05-32, Revision 0, "Onset of High Frequency Flow Induced Vibration in the Main Steam Lines at Susquehanna Unit 2: A Subscale Investigation of Standpipe Behavior," issued March 2006, describes the CDI SMT method. Small-scale models (1/5.87) of MSLs B and A (or D) of SSES were constructed and tested. The model consisted of a pressurized air tank connected to a single pipe modeling the steamline.

The tests confirmed the predicted resonance frequency of the full-scale standpipes to be near 217 Hz and the frequency of the full-scale dead leg piping to be near 15 to 16 Hz. Further, the onset of the standpipe resonance is found to occur at a Mach number (M = 0.18) which is substantially higher than the CPPU conditions (M = 0.1). However, a weak acoustic resonance of the standpipes may be excited at (or near) the CPPU by the second shear layer mode (also known as the double vortex mode). Regarding the pressure fluctuations near 15 Hz in the dead leg piping, the normalized acoustic pressure was found to be small and did not increase substantially when the load increased from the CLTP to the CPPU.

In general, the NRC staff concurs with PPL that strong resonance of the standpipes of the safety valves attached to lines B and C is not expected to occur when the power is increased to the CPPU. A weak resonance, however, may occur at or near CPPU conditions. PPL points out that it did not use the SMT to define dryer loads or assess dryer structural integrity but to determine whether any acoustic resonances in downstream valve standoff pipes would be excited at or near EPU conditions.

GE Scale Model Testing

The GE SMT method is described in GENE-0000-0054-2552-01-P, "Test Report #1 Susquehanna Steam Electric Station, Unit 1 Scale Model Test," issued October 2006. The report presents a description of a subscale model of SSES Unit 1 (including dryer and all four MSLs) and the results of its testing. The pressure fluctuations were measured in more than 100 locations, including the MSLs, the steam dryer inside and outside surfaces, the dryer bank panels, and the interior wall of the pressure vessel dome. The test program included sensitivity tests of the length of safety valve standpipes, as well as the length of MSLs. The model was tested at various power levels up to 130-percent OLTP.

The model scale is small (1/17) and is tested with air at atmospheric pressure. [[

]] The test results show that the acoustic resonances of relief valves are not excited at any load up to EPU conditions. [[

]] The NRC staff believes that the most important finding of the GE SMT, which agrees with the CDI SMT results, is that valve resonance is not expected to occur when the power is increased up to 120-percent OLTP.

2.2.6.1.3 <u>Main Steamline Strain Gauges</u>

PPL has installed two groups of strain gauges on each MSL in SSES Unit 1. There are four gauges in each group, oriented circumferentially and spaced 90 degrees apart. The gauge signals are summed to filter out the circumferential component of the strain resulting from bending of the pipe, and the resulting hoop strain is multiplied by a calibration factor to convert it to internal fluctuating pressure. This approach has been used successfully at other plants. PPL has installed strain gauges on the MSLs of Unit 2 to confirm the similarities in dryer loading during power ascension testing.

During SSES Unit 1 MSL strain gauge testing at 85-percent OLTP, PPL slowly closed the MSIV of one MSL at a time, leaving the other three MSIVs open. This increased the steamflow in the three open lines to 113 percent of OLTP. Since a complete set of MSL measurements (all four lines) was not possible during the MSIV slow closure test, PPL combined the strain gauge time histories from each group of three MSLs with one time history from another group, adjusting the phasing of the single time history to maximize dryer loads. The worst-case combination was chosen for the PPL load and stress analysis. The NRC staff considers this approach reasonable for SSES.

2.2.6.1.4 <u>Steam Dryer Load Development</u>

CDI Report 06-22, Revision 0, “Hydrodynamic Loads at OLTP, CLTP, and 113% OLTP on Susquehanna Unit 1 Steam Dryer to 250 Hz,” issued September 2006, provides the SSES ACM load definitions for OLTP, CLTP, and simulated 113-percent OLTP conditions. CDI Report 05-28P, “Bounding Methodology to Predict Full Scale Steam Dryer Loads from In-Plant Measurements,” Revision 2, dated October 2006, provides the benchmark of the ACM methodology.

Steam Dryer Loads

In CDI Report 06-22, PPL used the signals of strain gauges on the MSLs of SSES Unit 1 to predict the loading function on the dryer by means of the ACM methodology. The in-plant measurements were performed at OLTP, CLTP (106-percent OLTP), and 85-percent CLTP with one MSIV closed. The latter case was performed to simulate 113 percent OLTP and predict the dryer load at this power level. The pressure signals, obtained from the strain gauges, were conditioned before they were fed into the ACM. This involved filtering out “exclusion frequencies” associated with the vane passing frequency and its harmonics, as well as the alternating current (ac) supply noise at multiples of 60 Hz. An 80-Hz component was also removed in postprocessing because it was considered to be nonphysical. The filtered signals were then modified using the coherence function between the upstream and downstream strain gauges on each line. These signals were then used to predict the dryer load by means of the ACM method.

In Attachment 1 to PPL letter PLA-6176 dated April 27, 2007 (Reference 36), PPL stated that it used the ACM bounding peak pressure model for SSES. The NRC staff considers it acceptable for the licensee to use the bounding peak pressure ACM, where PPL includes ACM bias error and uncertainties or a bounding SUPF.

CDI has filtered the strain gauge signals to remove several frequency components. The unfiltered signals show strong tones at electrical frequencies of 60, 120, 180, and 240 Hz, along with tones at 46 Hz (recirculation pump motor electrical supply frequency) and 229 Hz (10 times the recirculation pump vane passing frequency). These tones have been removed from the filtered data used to compute dryer loads. Also, only the signals coherent between upper and lower sensors in an MSL are used to define dryer loads, as the localized pressures (mostly the result of flow turbulence) which are unrelated to dryer loads are filtered. The procedure PPL used to define the inputs to the ACM dryer loading model appears reasonable.

[[

]]

In CDI Report 06-22, CDI states that the load computed by ACM at 113 percent OLTP power level is conservative by about 24 percent. In Attachment 10 to PLA-6076, this conservatism is considered as a positive bias in the load definition process (U5b = +24 percent). The staff asked PPL to explain the assumed 24-percent conservatism in the ACM predictions though the low-frequency loading on the dryer at OLTP is underpredicted by ACM. In Attachment 1 to

PLA-6176, PPL states that actual dryer data will be obtained at 113-percent OLTP during power ascension and will be used to evaluate the load definition predicted by the ACM. A new uncertainty evaluation will also be performed.

Section 1 of CDI Report 06-22, states, “This model [acoustic circuit model (ACM)], validated against the Exelon full scale data, is used in this effort.” The NRC staff’s RAIs noted that the comparison of the ACM results with the Exelon full-scale data does not reveal good agreement. The staff asked PPL to reconsider bias error and random uncertainty in determining the loads on its dryers using the ACM and evaluate the resulting fatigue margins. In PLA-6200 (Reference 37), PPL stated that it used a spatial averaging procedure, similar to that used by Vermont Yankee, which grouped hood sensors from the Quad Cities instrumented dryer into six groups of three, then found an average over those groups. PPL deviated from the Vermont Yankee approach by computing bias and uncertainty over a wide frequency range around the 156-Hz tone in Quad Cities (before the installation of acoustic side branches). Rather than compute bias and uncertainty between 155 and 157 Hz, PPL chose a frequency range that extended ±10 percent about 156 Hz. This allowed PPL to include other peaks in the estimate which the ACM simulated more accurately, thus masking the underpredictions around156 Hz. While the NRC staff does not fully agree with the PPL estimates of ACM bias and uncertainty, the staff nevertheless concurs with the [[ ]] SUPF used by PPL to offset the ACM bias and uncertainties.

Benchmark against 1985 Unit 1 Instrumented Dryer Test Data

GE MDE #199-0985-P, Revision 1, “Susquehanna-1 Steam Dryer Vibration Steady State and Transient Response—Final Report,” January 1986, presents the measured strains, vibrations, and pressures on the instrumented SSES Unit 1 dryer at several plant conditions. [[

]] No plots of accelerations or pressures extend beyond 100 Hz, so the strength of the 110-Hz tone in those sensors cannot be determined. However, Figures 5-21 and 5-22 of GENE-0000-0057-4166-R1-P, “Susquehanna Steam Dryer Fatigue Analysis,” issued September 2006, show pressure spectra up to 200 Hz. [[

]]

The low-frequency (less than 50-Hz) tones did not shift in frequency as plant power increased, indicating that they are associated with acoustic and/or structural resonances. PPL states that the pressure amplitudes increased with the square of MSL flow velocity. At OLTP, the fluctuating pressure amplitudes on the surface (not differential across the surface) were between 0.6 and 1 psi (which is not as high as those in the Quad Cities 1 and 2 plants before the installation of acoustic side branches).

In PLA-6176 (Reference 36), PPL explained that an SUPF of [[ ]] was computed by comparing measured strains in the 1985 Unit 1 dryer with simulated strains using its FEM and ACM pressure-loading inputs. PPL applies the SUPF to the predicted stress intensities on the SSES steam dryer. [[

]]

Benchmarking of CDI Acoustic Circuit Models

[[

]]

2.2.6.1.5 End-to-End Uncertainty Discussion

Table 4-13 of Attachment 10 to PLA-6076 lists all bias errors and uncertainties associated with the PPL approach to dryer stress assessment. The SUPF accounts for the bias associated with the ACM and the FEM. However, PPL asserted a positive bias credit of 24 percent for 113-percent OLTP load definition, citing the CDI report on SSES dryer load definitions.

In an RAI, the NRC staff asked PPL to reconcile the CDI conclusion that the loads at 113-percent OLTP are conservatively biased by 24 percent (CDI Report 06-22) with Figures 5-21 and 5-22 of GENE-0000-0057-4166-R1-P, which shows significant pressure load underpredictions compared to the 1985 dryer pressure measurements. In PLA-6176 (Reference 36), PPL pointed out that the ability of ACM to simulate dryer loads is nonconservatively biased by 95 percent and has an uncertainty of ±22.8 percent. PPL accounted for this bias and uncertainty with an SUPF of [[ ]]. The NRC staff considers this approach to be acceptable for SSES.

2.2.6.1.6 Finite-Element Analysis

In GENE-0057-4166-R1-P, PPL presented the finite-element stress analysis results for the original steam dryer installed at SSES Units 1 and 2. In this report, PPL found that the fatigue stresses in some steam dryer components would exceed fatigue limits under EPU conditions.

Therefore, PPL decided to install replacement dryers at both SSES units. GENE-0000-0061-0595-P-R0, “Susquehanna Replacement Steam Dryer Fatigue Analysis,” issued December 2006, presents the fatigue stress analysis results for the replacement dryer. PPL later found that the FEM for the replacement dryers used incorrect boundary conditions. The stress analysis results presented in GENE-0000-0061-0595-P-R1, issued June 2007, corrected this error.

Revision 1 of GENE-0057-4166-P estimated the pressure loading on the steam dryer at 113-percent OLTP with the aid of a CDI ACM model, which used the MSL strain gauge measurements. Section 5.3 of the report compares the predicted pressure time histories at the maximum pressure locations on the outer hoods with the measured time histories on the cover plate of the 1985 steam dryer (Figures 5-21 and 5-22) and concluded that the frequency content [[ ]] of these two time histories compare reasonably well. Therefore, the finite-element analysis results are reasonable.

Scaling to EPU was done by extrapolating the dynamic pressure measurements available from three sources of data—(1) 1985 in-plant instrumented dryer measurements, (2) the MSL pressure measurements, and (3) SSES-specific SMT. Based on these extrapolations, [[ ]] was determined for scaling the dynamic pressure on the dryer from OLTP to EPU conditions.

The SSES steam dryer is modeled with shell finite elements, which are not capable of predicting the stress concentration in the welds. Therefore, weld factors are applied to the maximum stress intensities calculated at the weld locations by the shell model. These stresses are then multiplied by the appropriate scaling factor and SUPF to determine fatigue margin for different dryer components. For a given dryer component, this margin should be greater than the corresponding structural uncertainty margin for the component so that the component can be considered acceptable with regard to fatigue consideration. Structural uncertainty margins are calculated by [[ ]]

The report GENE-0000-0061-0595-P-R0 presents the fatigue analysis of the replacement dryer. The main objective of the fatigue analysis is to predict the replacement dryer’s susceptibility to fatigue damage under the FIV loads and mechanically induced vibration loads during normal operation at EPU power levels. [[ ]]

The finite-element analyses were performed using the loads developed by CDI based on the steamflow conditions representative of 113-percent power. The calculated finite-element stresses were multiplied by an SUPF of [[ ]] and appropriate weld factors to determine the fatigue stresses at 113-percent OLTP. The stresses at 113-percent OLTP are then extrapolated to 120-percent OLTP using the scale factor of [[ ]], which was determined in the GE report GENE-0000-0057-4166-R1-P. The extrapolated stresses satisfy fatigue design criteria at 120-percent OLTP for all components of the steam dryer [[ ]] The extrapolated stresses showed that the fatigue margins for these two components were smaller than their structural uncertainties. Therefore, these two components were reanalyzed using refined models; the resulting stresses satisfied the fatigue design criteria.

In Table 7-2 of GENE-0000-0061-0595-P-R0, the stresses from the finite-element analysis for the replacement dryer at 113-percent OLTP are multiplied by the weld factor, SUPF, and scale factor (for stress extrapolation to 120-percent OLTP), and fatigue margins are determined. In

Attachment 1 to PLA-6176, PPL stated that the design details such as the exact joint geometry and weld size were not available at the time of the analysis. The weld factors used in the replacement dryer analysis were chosen such that the original dryer's weld factors were used when applicable (i.e., no change anticipated in the joint and weld geometry), and a weld factor of [[

]] Even with structural uncertainty determined in the ±10 percent frequency shift analyses included, these components would have sufficient margin for EPU operation. These results demonstrate the acceptability of the replacement dryer design.

Since the fatigue analysis presented in GE-NE-0061-0595-P-R0 does not include the details of weldment designs in the replacement steam dryer, the NRC staff asked PPL to provide a summary of the stress analysis report (bounding licensing case) for the replacement dryer. In Attachment 1 to PLA-6242 (Reference 38), PPL stated that there are several improvements in the fabrication of the SSES replacement dryer beyond those assumed in the fatigue analysis in GE-NE-0000-0061-0595-P-R1. The improvements include increased thicknesses for the components susceptible to high-fatigue stresses, modified design of components, modified weldment designs replacing the fillet welds with full-penetration welds and placing welds away from high-stress locations, and solution annealing of several components and weldments with high residual stresses. In addition, some welds have been eliminated. As a result, the maximum stress intensities in the replacement steam dryer would be lower than those reported in GE-NE-0000-0061-0595-P-R1 and would satisfy the ASME Code fatigue requirements of 13,600 psi. In Appendix 3 to Attachment 1 to PLA-6242 (Reference 38), PPL lists 20 components having [[ ]] design as compared to the original dryer. The NRC staff finds the response acceptable.

In addition to toes of the fillet welds, the NRC staff was concerned about the roots of the fillet welds also being susceptible to stress concentration and fatigue cracking. The staff asked PPL to explain how it accounts for the fatigue strength reduction factor for the roots of the fillet welds in the fatigue analysis of the replacement steam dryer for SSES Units 1 and 2. In Attachment 1 to PLA-6242, PPL stated that the construction of the SSES replacement dryer requires that the first pass of any multiple-pass weld be examined for weld quality using liquid penetrant testing (PT). This is in addition to the requirement that the final welds also be examined using PT. This testing requirement provides additional confidence in the weld quality for the SSES replacement steam dryer. In addition, PPL submitted GE-NE-0000-0039-4817-1, "Recommended Weld Quality and Stress Concentration Factors for use in the Structural Analysis of Exelon Replacement Steam Dryer," which justifies the use of [[ ]] as a weld fatigue factor for fillet weld as it is applied to the peak stress intensity from the finite-element analysis. The NRC staff finds the response acceptable because the root pass of all fillet welds in the replacement dryer would have been inspected using PT, and if any defects had been detected, they would have been repaired.

In an RAI, the staff asked PPL to provide validation of the FEM of the replacement dryer. In Attachment 1 to PLA-6176, PPL explained that hammer tests on one dryer will be used to validate the FEM (in nonreactor conditions) by comparing simulated and measured modal and frequency response functions. If necessary, the FEM will be revised to better match experiments. Testing will be performed at four different water levels around the skirt.

The NRC staff asked PPL to provide natural frequencies of the dryer components and the pump vane passing frequency at 120-percent OLTP. If any component experiences a resonance with the pump vane passing frequency, PPL was asked to explain how the fatigue evaluation of that component accounts for the resulting stresses. In Attachment 1 to PLA-6176, PPL showed images of several dryer modes that might be excited by the recirculation pump vane passing frequency. Since any of these modes might be excited, PPL indicated that an approximate forcing function may be developed for the frequency using 1985 in-plant accelerometer and 1994 recirculation piping vibration measurements. The stresses would be combined with those resulting from pressure loads using the square-root-of-the-sum-of-the-squares (SRSS) method. The staff asked PPL to explain how and when the proposed forcing function would be developed and also to explain when the corresponding fatigue evaluation would be performed and the results submitted for NRC staff review. In Attachment 1 to PPL letter PLA-6255, dated August 13, 2007 (Reference 39), PPL further explained that the information from the accelerometers during power ascension, along with the 1985 in-plant accelerometer data, includes motions at the steam dryer support lug locations. The input accelerations, if significant, will be applied to the steam dryer FEM support lugs location during the steam dryer reanalysis following the first two CPPU steps on Unit 1.

2.2.6.2 Steam, Feedwater, and Condensate Systems and Components

In Attachment 9 to PLA-6076, PPL provided information regarding its susceptibility review of plant system piping and components that might be affected adversely by FIV under EPU conditions at SSES Units 1 and 2. PPL stated that vibration acceptance criteria are included in the SSES Unit 1 and 2 EPU power ascension program. PPL used the methodology of ASME O/M-S/G Part 3.

Vibration monitoring will be performed during startup at plateaus beginning with 75 percent of CLTP and proceeding at varying increments to EPU conditions. The piping systems located inside containment are being monitored for vibration using accelerometers. The piping systems located outside of containment generally will be monitored using portable vibration instrumentation or remote monitoring sensors in inaccessible areas. Additional monitoring instrumentation will be installed if initial measurements indicate that screening criteria could be exceeded.

PPL will monitor the MS, FW, recirculation, RHR, and extraction steam systems with remote vibration instrumentation. PPL will monitor the condensate system, HPCI system, EHC system, and FW drains with localized or portable vibration instrumentation. Vibration data have been collected from accelerometers installed in Unit 1 since spring 2006 and in Unit 2 since spring 2005. Based on data collected to date, PPL does not expect the vibration levels to exceed the screening criteria at EPU conditions.

PPL stated that visual inspections are a key part of the FIV evaluation strategy. PPL is planning walkdowns for pre-CPPU, CPPU first step (7 percent), CPPU second step (7 percent), and post-CPPU conditions. The walkdowns will include the MS, FW, condensate, extraction steam, FW heater drains, main turbine EHC, and HPCI steam (outside containment) systems. The walkdown criteria include condition of insulation and pipe supports, piping, attached components and branch lines, condition of structures and components adjacent and below, and other specific criteria for particular systems.

PPL is making modifications to reduce the susceptibility of piping to FIV. For example, it has added supports to FW drain lines. PPL will evaluate vibration data and walkdown information to determine if additional modifications are appropriate.

PPL is specifically addressing SRVs for FIV during EPU conditions. PPL has located vibration accelerometers on selected SRV bodies and adjacent discharge piping. The licensee will also inspect SRVs and other valves for FIV degradation at each of the four CPPU phases. In addition, PPL has reviewed the sample probes in the flow stream of piping systems affected by the CPPU and will monitor those probes for their performance.

2.2.6.3 Power Ascension Plan

Section 5 of Attachment 10 to PLA-6076 provides an overview of the SSES EPU Power Ascension Test Plan. PPL stated in a public meeting on February 27, 2007, that it will provide the detailed Power Ascension Test Plan to the NRC before increasing power above CLTP. The NRC staff asked PPL to provide the test and instrumentation plan and configuration of the new dryer as soon as they are available. The staff also asked PPL to provide its limit curves for power ascension, including the margin available from the fatigue stress limit if the curve is reached during power ascension.

In PLA-6176 (Reference 36), PPL explained that it plans to use a two-step approach for monitoring dryer stresses during power ascension. In the first step, the instrumentation in the steam dryer in Unit 1 would be monitored for power levels up to 107-percent CLTP. Limits on dryer strains, accelerations, and pressures would be based on dryer stress analyses conducted before power ascension. In the second step, the instrumented dryer data would be used to benchmark the stress analysis procedure, so that updated stress estimates would be made, and a new set of limit curves for the MSL strain gauge arrays could be generated. The new MSL limit curves would be used for power ascension of Unit 2 and for completing the power ascension of Unit 1 (from 107- to 114-percent CLTP).

Monitoring limits will be established for the strain gauges and accelerometers installed on the new dryer for Unit 1. Accelerometers on the support ring directly above the vessel support lugs will be used to monitor tones near 100 Hz from the recirculation pump, and pressure sensors and strain gauges on the dryer will monitor acoustic and hydrodynamic loading and dryer response, including relative phasing.

In PLA-6242 (Reference 38), PPL stated that it will establish sufficient hold periods to allow NRC review of steam dryer data acquired during Unit 1 power ascension. PPL stated that it will use pressure and strain measurements from the instrumented Unit 1 dryer to benchmark its load definitions and finite-element analyses at different power levels, including MSIV slow-closure conditions which emulate 114-percent CLTP in three of the four MSLs. PPL will confirm that (1) the [[ ]] SUPF is adequate and (2) the [[ ]] scaling factor used to increase stresses computed at 107-percent CLTP to stresses at 114-percent CLTP (EPU conditions) is conservative. If necessary, PPL will modify its stress simulation procedure and/or the SUPF and scaling factor to account for any nonconservative bias errors. The NRC staff finds this plan adequate.

PPL explained that it will spread power ascension to EPU in Unit 1 over two operating cycles. The dryer instrumentation can be used only during the first operating cycle and will likely be made unavailable by refueling operations before the second operating cycle. PPL chose to instrument the Unit 1 dryer since this unit will be increased in power first and thus provide dryer strains, pressures, and accelerations as soon as possible. PPL will conduct MSIV slow-closure testing in Unit 1 before the increase in power above CLTP, so that dryer data may be acquired for MSL flow rates corresponding to full EPU power. Although the flow field over the dryer surfaces during MSIV slow-closure testing is not identical to that during actual EPU operation (when all MSLs are open), it should be similar enough to the actual flow to reveal the presence of any strong hydrodynamic sources within the RPV. The NRC staff finds the PPL approach to be reasonable.

For Unit 1, PPL will conduct MSIV slow-closure testing to simulate EPU dryer loads caused by local hydrodynamic flow over the dryer and acoustic pressures within the MSLs, including those amplified by acoustic resonances within valve standoff pipes or dead legs. PPL will confirm the accuracy of both the SUPF [[ ]] and the scaling factor [[ ]] used to increase stresses between 107-percent and 114-percent CLTP. The benchmarking may include modifications to these factors and/or the elements of the stress simulation procedure. In the unlikely event that a new acoustic source appears that was not identified during the MSIV slow-closure test, the MSL monitoring will identify this new source. If the new acoustic source is significant and challenges the Level 2 or Level 1 limit curves, the power ascension will be held at an acceptable power level, and the impact of the new source on the dryer will be evaluated. The NRC staff finds this plan acceptable.

In Attachment 1 to PLA-6242, PPL developed monitoring limits for Unit 1 power ascension to 107-percent CLTP for both (1) the instrumented Unit 1 dryer instrumentation (strain gauges and accelerometers), as described in Appendix 5 to PLA-6242, and (2) the MSL strain gauge arrays, as described in Appendix 1 to PLA-6242. Monitoring limits for the MSL strain gauge arrays will be recomputed following Unit 1 interim power ascension and the recalibration of the dryer stress estimating procedure based on instrumented dryer data. The dryer and MSL limits are based on stress analyses performed at 113-percent OLTP conditions (or 107-percent CLTP), based on MSL inputs measured during MSIV slow-closure testing at about 80-percent CLTP.

PPL provided a detailed description of how it will establish instrumented dryer limit curves based on finite-element stress analysis results (including the effects of SUPFs and uncertainties). The Level 1 (13,600 psi) and Level 2 (11,000 psi) criteria will be used to set the limits. Finite-element calculations at nominal loading conditions, and eight other loading conditions over 2.5-percent time shifts between ±10 percent are considered, and the maximum stress for each of the loading conditions is conservatively applied in setting the limit curves. The ratios of the ASME Code fatigue limit (13,600 psi) and the maximum stresses are used to set the limits on the dryer strain gauges. A similar approach is used to set limits on the dryer accelerometers. Dryer pressure transducer limits are based on the design load frequencies and amplitudes, where all measured peak frequencies must be within ±20 percent of the design frequencies, and all measured peak amplitudes must be no more than 30 percent higher than the design amplitudes.

Table 3 of Appendix 1 in Reference 38 lists the final load definition bias and overall uncertainty (load definition, instrumentation, use of a limited time sample, combined by SRSS), which are summed and multiplied by the highest stresses computed from a series of run conditions at variable frequency shifts [[
]]. These stresses, subsequently multiplied by weld factors, are compared to the allowable limit of 13,600 psi to compute limit curve factors. The smallest (conservative) limit curve factor of 1.75 based on the thick end plate is used to compute MSL limit curves.

The MSL limit curves, shown in Figure 4 of Appendix 1, are computed by multiplying the measured MSL spectra at 113-percent OLTP (obtained during MSIV closure tests) by $(1.75)^2$ (spectra are $(\text{microstrain})^2/\text{Hz}$). The limit curves have lower bounds based on strain gauge array noise floors. PPL compares the limit curves to MSL data acquired at the QC2 plant before the installation of acoustic side branches on the QC2 MSL valve standoff pipes. The SSES limit curves are significantly lower than the QC2 data at frequencies above 100 Hz (where QC2 was loaded by significant valve resonance, or “singing” tones), are comparable to the QC2 data at frequencies between 60 and 100 Hz, but exceed QC2 data at frequencies below 60 Hz, particularly at the 15-Hz frequency associated with the dead legs on MSLs A and D.

The NRC staff finds the PPL power ascension plan, including the dryer strain gauge, accelerometer peak-to-peak limit, and the MSL strain gauge spectra limits, reasonable.

Conclusion

The NRC staff has reviewed the licensee’s consideration of potential adverse flow effects on the MS, FW, and condensate systems and their components (including the steam dryer) for operation of SSES Unit 1 and 2 at EPU conditions. The staff concludes that the licensee has provided reasonable assurance that the flow-induced effects on the steam dryer and other plant equipment are within the structural limits at CLTP conditions and extrapolated CPPU conditions. The staff further concludes that the licensee has demonstrated that the MS, FW, and condensate systems and their components (including the steam dryer) will continue to meet the requirements of GDC 1, 2, 40, and 42 following implementation of the proposed EPU at SSES Units 1 and 2, subject to the license conditions in this SE. Therefore, the NRC staff finds the proposed license amendment to operate SSES Units 1 and 2 at EPU conditions to be acceptable with respect to potential adverse flow effects.

2.2.7 Environmental Qualification of Mechanical Equipment

Regulatory Evaluation

Environmental qualification (EQ) of mechanical and electrical equipment involves demonstrating that the equipment is capable of performing its safety functions under the significant environmental stresses that could result from DBAs. The NRC staff’s review focused on the effects of the proposed power uprate on the environmental conditions that the mechanical and electrical equipment will be exposed to during normal operation, AOOs, and accidents. The staff conducted the review to ensure that the equipment will continue to be capable of performing its safety functions following implementation of the proposed power uprate. The NRC’s acceptance criteria for EQ of mechanical equipment are based on the relevant requirements in 10 CFR Part 50. SRP Section 3.11 contains specific review criteria.

Technical Evaluation

Appendices A and B to 10 CFR Part 50 provide general requirements related to EQ of mechanical equipment. In particular, components must be designed to be compatible with the postulated environmental conditions, including those associated with LOCAs. Measures must be established for the selection and review of the suitability of application of materials, parts, and equipment that are essential to safety-related functions. Design control measures must be established for verifying the adequacy of design. Equipment qualification records must be maintained and include the results of tests and materials analyses.

For the EQ of mechanical equipment, the NRC staff focused its review on materials that are sensitive to environmental effects (e.g., seals, gaskets, lubricants, fluids for hydraulic systems, and diaphragms). Mechanical equipment experiences the same environmental conditions as defined in 10 CFR 50.49, “Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants,” for electrical equipment.

In section 2.3.1 of this SE, the NRC staff describes its evaluation of the capability of electrical equipment to continue to perform safety functions under power uprate conditions. In that section, the NRC staff concluded that the licensee had adequately addressed the effects of the proposed power uprate on the EQ of electrical equipment at SSES. The NRC staff finds that the conditions used by the licensee in reviewing the EQ of electrical equipment are sufficient for the review of mechanical equipment in support of the proposed EPU for SSES.

In Section 10.3, Environmental Qualification, of Attachment 4 to its submittal dated October 11, 2006, the licensee indicated that safety-related components must be qualified for the environment in which they are intended to operate. In Section 10.3.2, Mechanical Equipment with Non-Metallic Components, the licensee stated that accident temperature, pressure, and radiation level increase as a result of the CPPU. The licensee stated that the design control program ensures that nonmetallic components are specified and procured for the environment in which they are intended to function. In an RAI, the NRC staff asked the licensee to identify the range of the nonmetallic components in safety-related mechanical equipment with examples. In its RAI response dated June 1, 2007 (ADAMS Accession No. ML071620311), the licensee discussed the (1) applicable environmental conditions, (2) required operating life, (3) capabilities of the nonmetallic components, (4) basis for the EQ of mechanical equipment, and (5) surveillance and maintenance program to be developed to ensure functionality during the equipment’s design life.

The licensee reported that the range of nonmetallic components used in safety-related mechanical equipment at SSES Units 1 and 2 includes packing, gaskets, component seals, valve seats, and O-rings. The licensee provided the applicable ambient temperatures, pressures, and humidity levels for the nonmetallic components in mechanical safety-related equipment in the primary containment, reactor building, and control structure. The licensee determined that operation at CPPU conditions does not result in ambient temperatures that exceed ambient design temperatures for those components. No ambient humidity levels or pressure changes will occur for the CPPU, except in containment where the post-LOCA pressure will increase by 4 psig. The licensee also indicated that FW temperature at full CPPU power will increase approximately 9 °F compared to CLTP conditions. The FW flow and MS flow increase approximately 14.5 percent between CLTP and CPPU conditions.

The licensee indicated that purchase specifications typically require that the operating life of mechanical equipment be a minimum of 40 years. The operating life of nonmetallic components in mechanical equipment varies according to application and maintenance frequency. Component replacement frequency is also based on operating experience and original manufacturer recommendations.

Qualification of mechanical components is based on satisfying design requirements included in purchase specifications, together with periodic testing and maintenance to ensure continued functionality. Environmental factors have limited effects on nonmetallic components, which are totally enclosed in their mechanical equipment. The normal ambient environmental conditions included in the original purchase specifications of mechanical equipment generally bound the CPPU conditions. However, some calculated ambient environmental conditions are slightly higher than original specified ambient conditions. Several mitigating factors minimize the impact of the environment on the ability of mechanical equipment to perform its safety functions. For example, the failure of the operator diaphragm for the RR pump cooling water isolation valves (air-operated butterfly valves) will cause the valve to close, which is its safety position. The licensee reported that design conditions for safety-related mechanical equipment will not be exceeded for operation at CPPU conditions. Through maintenance and testing, the licensee will identify any significant increase in degradation rates of mechanical components resulting from wear or erosion and will subsequently initiate repair or replacement.

The SSES Unit 1 and 2 Equipment Reliability and Station Health Process encompasses the identification of critical components, performance monitoring, corrective action, continuing reliability improvement, preventive maintenance, and long-term planning and life cycle management in an integrated way. The process evaluates the impact of a component's failure, monitors the effectiveness of the maintenance program, determines whether changes to maintenance or monitoring are needed based on corrective action evaluation, reviews operating experience for alternative strategies and improvements in maintenance, ensures appropriate maintenance activities for equipment function effectiveness, and assures long-term maintenance/replacement strategies to address aging and obsolescence. SSES Unit 1 and 2 procedures describe this process.

Conclusion

As discussed in this SE, the NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the EQ of mechanical equipment at SSES Units 1 and 2. The staff concludes that the licensee has adequately addressed the effects of the proposed EPU on the environmental conditions for and the qualification of mechanical equipment. The staff also concludes that the mechanical equipment at SSES Units 1 and 2 can withstand the environmental conditions specified in 10 CFR 50.49 for electrical equipment following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the EQ of mechanical equipment at SSES.

2.3 Electrical Engineering

2.3.1 Environmental Qualification of Electrical Equipment

Regulatory Evaluation

The EQ of electrical equipment involves demonstrating that the equipment can perform its safety function under the significant environmental stresses that could result from DBAs. The NRC staff's review focused on the effects of the proposed EPU on the environmental conditions that the electrical equipment will be exposed to during normal operation, AOOs, and accidents. The staff conducted the review to ensure that the electrical equipment will continue to be capable of performing its safety functions following implementation of the proposed EPU. The NRC's acceptance criteria for EQ of electrical equipment are based on 10 CFR 50.49, which specifies the requirements for the qualification of electrical equipment important to safety that is located in a harsh environment. SRP Section 3.11 contains the specific review criteria.

Technical Evaluation

In Section 10.3.1 of Attachment 6 to the LAR (Reference 1), the licensee stated that the safety-related electrical equipment was reviewed consistent with the requirements of 10 CFR 50.49 to ensure that the existing qualification remains adequate for the normal and accident conditions expected in the installed locations as a result of the CPPU. The 10 CFR 50.49 acceptance criteria, which include pressure, temperature, humidity, and radiation requirements, were the basis for this determination.

Inside Containment

According to Table 10-2 in Attachment 6 to the LAR, the licensee stated that the CPPU would affect the following EQ parameters inside of primary containment:

- normal radiation levels: ≤14% increase
- postaccident peak temperature: 16.3 °F increase
- postaccident peak pressure: 4.0 psig increase
- postaccident radiation: ≤13.8% increase (wetwell)
  ≤14.7% increase (drywell)

The EQ temperature profile used for DBA qualification of safety-related electrical equipment bounds the CPPU peak temperature. The increased drywell peak pressure that results from the CPPU is also bounded by the existing qualification levels of the drywell EQ equipment.

Regarding the impact of increased radiation levels as a result of the CPPU, the licensee provided the following supplemental information in its RAI response dated May 9, 2007 (ADAMS Accession No. ML071420064):

> The radiation dose analysis for EQ equipment inside primary containment under CPPU conditions demonstrates that all equipment inside primary containment (including power and instrument cables) are qualified for CPPU conditions. The worst-case reduction in the life of affected solenoid valves due to CPPU conditions inside the primary containment involves air-operated valve limit switch conduit seals. The conduit seals are qualified for the CPPU post-accident radiation levels with scheduled replacement every 13 years. This is reduced from a qualified life of 39.8 years.
>
> The PPL Susquehanna LLC (PPL) Equipment Reliability and Station Health Program is the management control program that assures EQ components are replaced to maintain environmental qualification. The change to the conduit seals component qualified life will be reflected in the preventive maintenance program. This program includes controls that identify and schedule replacement to assure replacement prior to the end of qualified life.

Outside Containment

According to Table 10-2 in Attachment 6 of the LAR, the licensee stated that the CPPU would affect the following EQ parameters outside of primary containment:

- normal radiation levels: ≤20-percent increase
- postaccident radiation: ≤20.5-percent increase (in control structure near SGTS filters) and ≤18-percent increase (reactor building)

The EQ of safety-related electrical equipment installed outside primary containment is based on normal operating conditions and the effects of DBAs that occur inside primary or secondary containment. These accidents include main steamline break (MSLB) or LOCA inside primary containment and HELB or control rod drop accident (CRDA) in secondary containment. The qualification is based on the most limiting accident for the room under analysis.

As noted above, the CPPU may increase normal operating radiation levels up to 20 percent in some areas. This increase is less than the design-basis normal radiation levels used for EQ. As such, the normal operating radiation levels used for qualification are unchanged.

The licensee stated in its May 9, 2007, RAI response that it will replace any equipment determined to be unqualified for the CPPU conditions before CPPU implementation as determined by the radiation dose analysis completed in June 2007 for EQ equipment outside primary containment under CPPU conditions.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the EQ of electrical equipment and concludes that the licensee has adequately addressed the effects of the proposed EPU on the environmental conditions for the qualification of electrical equipment. The staff also concludes that the electrical equipment will continue to meet the relevant requirements of 10 CFR 50.49 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the EQ of electrical equipment.

2.3.2 Offsite Power System

Regulatory Evaluation

The offsite power system includes a minimum of two physically independent circuits capable of operating independently of the onsite standby power sources. The NRC staff's review covered the descriptive information, analyses, and referenced documents for the offsite power system and the stability studies for the electrical transmission grid. The review focused on whether the loss of the nuclear unit, the largest operating unit on the grid, or the most critical transmission line will result in the loss of offsite power (LOOP) to the plant following implementation of the proposed EPU. The NRC's acceptance criteria for offsite power systems are based on GDC 17, "Electric Power Systems." SRP Sections 8.1 and 8.2, Appendix A to SRP Section 8.2, and BTPs PSB-1, "Adequacy of Station Electric Distribution System Voltages," issued July 1981, and ICSB-11, "Stability of Offsite Power Systems," contain specific review criteria.

Technical Evaluation

The licensee provided the details of EPU impact on the ac power system in Section 6.1 of Attachment 6, "Susquehanna Steam Electric Station Units 1 and 2 Safety Analysis Report for

Constant Power Pressure Uprate," and Attachment 11, "Grid Stability Evaluation," of the LAR (Reference 1).

2.3.2.1 Grid Stability

According to Attachment 11 of the licensee's LAR, the proposed SSES EPU electrical power output is 1300 MWe for each unit. The power from Units 1 and 2 is distributed through the 230-kilovolt (kV) and 500-kV system respectively, through two 500-kV transmission lines, seven 230-kV transmission lines, and one 500/230-kV transformer.

SSES Units 1 and 2 are part of the Pennsylvania, New Jersey, Maryland Interconnection, LLC (PJM), bulk power system which is planned in accordance with Mid-Atlantic Area Council (MAAC) Reliability Principles and Standards. (Reliability First Corporation is the successor organization to MAAC, the East Central Area Coordination Agreement, and the Mid-American Interconnected Network. Reliability First currently uses legacy MAAC standards.) PJM performed the impact studies for the SSES Unit 1 and 2 EPU and tested the compliance of the system with the MAAC Reliability Principles and Standards. In its letters dated May 9 and June 20, 2007, the licensee clarified that the PJM 230-kV transmission system is operated with a normal minimum voltage limit of 219 kV. In the SSES plant degraded voltage protection studies, the 230-kV minimum voltage is considered as 216.7 kV under LOCA and a switchyard 500/230-kV transformer outage. If the monitored SSES switchyard buses are at or below the SSES allowable minimum voltage of 216.7 kV, the transmission operator is required to notify SSES.

The following briefly describes the transmission studies performed by PJM as described in Attachment 11 of the licensee's LAR:

> The power flow portion of the stability analysis consisted of testing the system under normal and emergency conditions. The transmission system was studied under normal conditions in order to assess the transmission network element loading with the addition of the proposed upgrades. The studies included simulations of heavy power transfer conditions followed by single and multiple transmission facility outages.

Under all power flow conditions, the stations and the transmission system satisfy the MAAC Reliability Principles and Standards. In some cases, the system becomes unstable during certain line or transformer outages. An operating guide (the PPL Electric Utilities (EU) National Environmental Policy Act (NEPA) memorandum) is in place that directs the reduction in power during these specific transmission outages. In its RAI response dated May 9, 2007, the licensee explained that while the NEPA memorandum is not an SSES procedure, the operating guidelines contained in the memorandum are for the use of PJM and PPL EU. Should an abnormal system configuration require the use of this operating guide, PPL EU will direct the SSES Unit 1 and 2 operators to take the appropriate actions with regard to generator loading.

In Attachment 11 of the LAR, the licensee further explained that maximum gross megavolt-amperes-reactive (MVARs) limitations on the generators will cause both real-time and postcontingency 500-kV voltage criteria deviations when some specific 500-kV lines are out of service. If this occurs, options, including a generation reduction at SSES, will be exhausted to correct the deviation to relieve the voltage violation. To accommodate the loss in reactive capability resulting from an increase in real power output, a 183-MVAR capacitor bank will be installed on the 230-kV substation bus, and a 171-MVAR capacitor bank will be installed on the 500-kV substation at SSES. In its RAI response dated May 9, 2007, the licensee clarified that the capacitor banks are switchable and can be put into service or removed from service by the transmission system operator. PPL EU will own and operate the supplemental capacitor banks.

In the grid stability studies, the following criteria were applied:

- Steady-state voltage: Prefault voltage at selected 500-kV buses is not above 1.1 per unit (pu) or below 1.0 pu.

- Transient stability: System must be stable for all faults considered.

- Transient voltage: Postfault transient voltages at 500-kV buses shall not be below 0.7 pu.

- The grid studies confirmed that the power system remains stable for all three-phase and single-phase faults studied, when cleared by primary protection in accordance with planned relay settings.

In its RAI response dated May 9, 2007, the licensee provided the following clarification regarding the impact of 0.7 pu postfault transient voltage on the plant undervoltage and degraded voltage protection:

> The clearing times for transmission protection schemes is less than 1 second, which is shorter than the plant undervoltage and degraded voltage protective relay minimum time delay of 3 seconds. The voltage on the transmission system would recover to within the normal transmission voltage limits once cleared by the appropriate transmission protective relaying. Therefore, while considered for grid stability, this post-fault transient voltage criteria used by PJM is not a requirement of the SSES design-basis for the plant undervoltage or degraded voltage protection. However, the plant undervoltage and degraded voltage protection time delay allows for the normal clearing of transmission type events and voltage recovery.

2.3.2.2 Main Generator(s)

According to the licensee's LAR, the main generator will be rewound to EPU conditions. The new megavolt-ampere (MVA) rating will be 1354 MVA (revised from the existing 1298 MVA). In its supplemental letter dated June 20, 2007 (ADAMS Accession No. ML071860421), the licensee stated that actual power at CPPU conditions will be approximately 1300 MWe. Currently, each unit is capable of producing approximately 1200 MWe.

2.3.2.3 Isophase Bus(es)

In Section 6.1.2 of Attachment 6 of the LAR, the licensee confirmed that each isolated phase bus duct is adequately rated at 35,000 amperes and supports the generator output (maximum 1354 MVA) at CPPU conditions.

2.3.2.4 Main Transformer(s)

In Section 6.1.2 of Attachment 6 of the LAR, the licensee stated that the existing SSES Unit 1 main transformers (rating 2 x 750 MVA) were determined to be adequate for operation at the CPPU-related electrical output of the generator (maximum 1354 MVA).

In letters dated May 9 and June 20, 2007, the licensee provided the following information about the SSES Unit 2 main transformer (consisting of three single-phase transformers) rating:

> The original equipment manufacturer (ABB) performed an engineering thermal study of the SSES Unit 2 transformers. The study concluded that the SSES units would be suitable for loading to 450 MVA without exceeding a 65 °C average winding rise, without exceeding a 80 °C winding hot spot rise, and without exceeding any of the transformer component ratings. Therefore, the rating increase of the transformers from 420 MVA to 450 MVA (total 1350 MVA for three transformers) did not require physical changes to the transformers.

2.3.2.5 Switchyard Components

In Section 6.1.2 of Attachment 6 of the LAR, the licensee stated that the 230-kV and 500-kV switchyard components, including circuit breakers, disconnect switches, and current transformers, are suitable to meet CPPU continuous current and short-circuit requirements after replacement of the 230-kV synchronizing breaker. The new rating of the 230-kV synchronizing breaker is suitable for EPU conditions.

2.3.2.6 Protective Relay Settings

In Section 6.1.2 of Attachment 6 of the LAR, the licensee stated that the protective relaying for the main generator, transformer, and switchyard is adequate for the CPPU generator output. In its RAI response dated May 9, 2007, the licensee clarified that the SSES Unit 2 overall differential protection relay does not require a setpoint change.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the offsite power system and concludes that the offsite power system will continue to meet the requirements of GDC 17 following implementation of the proposed EPU. Adequate physical and electrical separation exists, and the offsite power system has the capacity and capability to supply power to all safety loads and other required equipment. The staff reviewed the impact of the proposed EPU on grid stability. The grid studies are based on a 183-MVAR capacitor bank installed on 230-kV bus and a 171-MVAR capacitor bank installed on 500-kV bus. The installation of switchyard capacitor banks is necessary to meet PJM reactive power requirements. The capacitor banks are included in the list of planned modifications (Attachment 7 of the LAR) that are necessary to support the EPU for SSES Units 1 and 2. Based on this information, the NRC staff finds the proposed EPU acceptable with respect to the offsite power system.

2.3.3 AC Onsite Power System

Regulatory Evaluation

The ac onsite power system includes those standby power sources, distribution systems, and auxiliary supporting systems provided to supply power to safety-related equipment. The NRC staff's review covered the descriptive information, analyses, and referenced documents for the ac onsite power system. The NRC's acceptance criteria for the ac onsite power system are based on GDC 17, insofar as it requires the system to have the capacity and capability to perform its intended functions during AOOs and accident conditions. SRP Sections 8.1 and 8.3.1 contain specific review criteria.

Technical Evaluation

In Section 6.1.2 of Attachment 6 of the licensee's LAR, the licensee stated that the brake horse power of the recirculation motor-generator set motors increases 6.43 percent for the CPPU but remains within the nameplate capability. The electrical demand load of the condensate pump motors will increase for the CPPU but will remain within its nameplate rating.

Because the electrical demand associated with the power generation system does not change significantly, the existing load flow and short-circuit calculations can verify the adequacy of the onsite ac system for the CPPU conditions. The existing protective relay settings are adequate to accommodate the increased load on the 13.8-kV system. Selective coordination is maintained between the 13.8-kV switchgear main breaker and the supply breakers to the reactor recirculation motor-generator set and to the condensate pump motor feeder.

In its RAI response dated May 9, 2007, the licensee provided the following supplemental information:

> Load flow analysis was performed for the 13.8 kV buses with the new expected CPPU loading profile. The increase in loading to the 13.8 kV buses is a result of the increased loading to the condensate pump motors, which resulted from the installation of new higher head condensate pumps. Analysis was conducted to demonstrate the 13.8 kV buses and transformers have acceptable margin for the increase in bus loading due to the condensate pump motor loading increase. The increase to the Unit 1 and Unit 2 auxiliary transformer is approximately a 1% increase. This results in a total transformer load of about 48 MVA for Unit 1 and 47 MVA for Unit 2, which is below the 55 MVA rating of the auxiliary transformers. This increase in loading does not impact the plant design base accident loading since the condensate pumps are tripped as part of a plant auxiliary bus transfer scheme during a Design-basis Accident (DBA) condition. Therefore, the increase in condensate pump loading does not affect the DBA analysis.

At EPU conditions, the existing electrical distribution equipment will continue to operate at or below the nameplate rating; therefore, under emergency conditions, the electrical supply and distribution components remain adequate. The systems have sufficient capacity to support all required loads to achieve and maintain safe shutdown and to operate the ECCS equipment following accident and transients at EPU conditions.

The current emergency diesel generator (EDG) fuel oil storage volume, as required by the plant TSs, is based on the continuous full-load diesel rating and not on the DBA loads. The CPPU does not affect the emergency diesel fuel oil storage and transfer system. In its letter dated May 9, 2007, the licensee provided the following supplemental information:

> The SSES CPPU license amendment safety analyses did not identify the need to install modifications to SSES DBA mitigation equipment. Flows, pressures, and pump loads for DBA mitigation equipment have not changed because of the CPPU. The loads on the 4 kV safety buses, as documented in the SSES load tracking calculation, will not change because of CPPU. Since there are no changes to safety bus loadings, the ratings of the Emergency Diesel Generators are not impacted.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ac onsite power system and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system's functional design. The staff also concludes that the ac onsite power system will continue to meet the requirements of GDC 17 following implementation of the proposed EPU. Adequate physical and electrical separation exists and the onsite power system has the capacity and capability to supply power to all safety loads and other required equipment. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the ac onsite power system.

2.3.4 DC Onsite Power System

Regulatory Evaluation

The direct current (dc) onsite power system includes the dc power sources and their distribution and auxiliary supporting systems that are provided to supply motive or control power to safety-related equipment. The NRC staff's review covered the information, analyses, and referenced documents for the dc onsite power system. The NRC's acceptance criteria for the dc onsite power system are based on GDC 17, insofar as it requires the system to have the capacity and capability to perform its intended functions during AOOs and accident conditions. SRP Sections 8.1 and 8.3.2 contain specific review criteria.

Technical Evaluation

In Section 6.2 of Attachment 6 of the LAR, the licensee stated that a review of the dc loading requirements in the SSES Unit 1 and 2 FSAR identified no loads specifically dependent on reactor power level.

The dc power distribution system provides control and motive power for various systems/components within the nuclear power plant. In normal and emergency operating conditions, loads are computed based on equipment nameplate ratings. These loads are used as inputs for the computation of load, voltage drop, and short-circuit current values.

Operation at the CPPU conditions does not increase any dc load or revise any component operating duty cycle; therefore, the dc power distribution system remains adequate at EPU conditions.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the dc onsite power system and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system's functional design. The staff also concludes that the dc onsite power system will continue to meet the requirements of GDC 17 following implementation of the proposed EPU. Adequate physical and electrical separation exists, and the system has the capacity and capability to supply power to all safety loads and other required equipment. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the dc onsite power system.

2.3.5 Station Blackout

Regulatory Evaluation

Station blackout (SBO) refers to a complete loss of ac electric power to the essential and nonessential switchgear buses in a nuclear power plant. SBO involves the LOOP concurrent with a 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. The NRC staff's review focused on the impact 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 plant's licensing basis. The NRC's acceptance criteria for SBO are based on 10 CFR 50.63, "Loss of All Alternating Current Power." SRP Section 8.1, Appendix B to SRP Section 8.2, and other guidance provided in Matrix 3 of RS-001 contain specific review criteria.

Technical Evaluation

In Section 9.3.2 of Attachment 6 of the LAR, the licensee stated that the SBO analysis was reevaluated using the material access authorization program (MAAP) computer code at CPPU power levels and the guidelines provided in Nuclear Management and Resource Council (NUMARC) 87-00, "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors," issued November 1987.

Because of the higher initial power and the increased decay heat, operation at CPPU reactor thermal power has a slight effect on the plant responses and coping capabilities in an SBO event. Decay heat was calculated based on operation at 100-percent rated power for 100 days before the SBO. The systems and equipment used to respond to an SBO do not change, and the coping time (4 hours) remains unchanged.

Areas containing equipment necessary to cope with an SBO event were evaluated for the effect of loss of ventilation as the result of an SBO. The evaluation shows that equipment operability is assured by the conservatism in the existing design and qualification bases. The battery capacity remains adequate to support RCIC operation after the CPPU. Adequate compressed gas capacity exists to support SRV actuations.

The current condensate storage tank (CST) reserve (135,000 gallons) for RCIC use provides adequate water volume to remove decay heat, depressurize the reactor, and maintain the requisite reactor water level, for the 4-hour coping time at the CPPU. Peak containment pressures and temperatures remain within the design basis. Adequate net positive suction head (NPSH) margin exists for the RCIC pump during the event and the RHR pumps at the end of the event.

Based on the above information, SSES Units 1 and 2 would continue to meet the requirements of 10 CFR 50.63 at CPPU conditions.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects 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 plant's licensing basis. The staff concludes that the licensee has adequately evaluated the effects of the proposed EPU on SBO and demonstrated that the plant will continue to meet the requirements of 10 CFR 50.63 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to SBO.

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 ESF systems and essential auxiliary supporting systems, and (4) 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 reviewed 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 so that the systems continue to meet their safety functions. The staff review also checked 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 SSES Unit 1 and 2 UFSAR (GDC 1, 2, 4, 13, 19, 20, 21, 22, 23, 24, 25, and 29). SSES UFSAR Sections 7.1.2, 7.2, 7.3, 7.4, 7.5, 7.6, and 7.7 contain specific review criteria.

The NRC staff also considered the regulatory requirements and guidance of 10 CFR 50.36, "Technical specifications," and Regulatory Guide (RG) 1.105, Revision 3, "Setpoints for Safety-Related Instrumentation." 10 CFR 50.36 provides the regulatory requirements for the content required in a licensee's TS. 10 CFR 50.36 states, in part, that where a limiting safety system setting (LSSS) is specified for a variable on which a safety limit has been placed, the setting must be so chosen that automatic protective action will correct the abnormal situation before a safety limit is exceeded. RG 1.105, Revision 3, describes a method acceptable to the NRC staff for complying with the NRC regulations for ensuring that setpoints for safety-related instrumentation are initially within and remain within the TS limits.

Technical Evaluation

2.4.1 Suitability of Existing Instruments

For the proposed power uprate, the licensee evaluated each existing instrument of the affected NSSS and BOP systems to determine its suitability for the revised operating range of the affected process parameters. Where operation at the power uprate 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 SSES Units 1 and 2:

Parameter	Change
MSL High-Flow Switches	Replace the existing switches with new ones to encompass higher flow value and setpoint.
FW Flow	Re-span or replace transmitters, indicators, and associated loop instruments to encompass new flow range.
Condensate Flow	Re-span or replace transmitters, indicators, and associated loop instruments to encompass new flow range.
EHC Pressure Sensing	Install steamline resonance cards to dampen third harmonic frequency.
EHC Turbine Control Valve Digital Position	Modify turbine control valve digital position cards for new steamflow conditions.
EHC Power Load Imbalance	Recalibrate for new CPPU operating conditions.
Condensate Demineralizer Discharge Header Temperature	Re-span transmitters to encompass new range resulting from increased heat rejection rate. Condenser pressure and condensate demineralizer temperatures will be maintained within established limits.
RFP Hydrogen Injection Flow	Re-span transmitter to encompass new hydrogen flow range which will increase because of increased FW flow. However, near constant hydrogen concentration will be maintained in the FW.
Average Power Range Monitor (APRM) Flow Biased Simulated Thermal Power Scram Setpoints	Revise setpoints to CPPU values for both two-loop and single-loop operation.
APRM Flow Biased Simulated Thermal Power Rod Block Setpoints	Revise setpoints to CPPU values for both two-loop and single-loop operation.

APRM Neutron Flux Upscale Setdown Scram	Revise setpoints to CPPU values.
APRM Neutron Flux Upscale Setdown Rod Block	Revise setpoints to CPPU values.
RFP Hydrogen Injection High Flow	Change alarm setpoint.
RWM Low Power Setpoint	Revise setpoints to reflect increased steamflow at 10% RTP.
Offgas Recombiner Oxygen Injection Flow	Re-span transmitter to encompass new range.
Condensate Pump Suction Oxygen Injection Flow	Re-span transmitter to encompass new range.
RR Runback Limiter No. 2	Revise logic to remove the confirmatory low reactor water level trip signals from logic that initiates runback of RR system upon detection of trip of FW pump and/or condensate pump. Change condensate pump trip input signal to pump breaker position.
Standby Liquid Storage Tank Low Level	Change alarm setpoint.
Standby Liquid Storage Tank High Level	Change alarm setpoint.
SLCS Logic	Revise system logic to allow for single pump initiation.
Offgas Recombiner Steamflow	Re-span transmitter to encompass new range.
MSL Flow	Re-span transmitters, indicators, and associated loop instruments to encompass new range.
MSL Differential Pressure	Change alarm setpoint.
Reactor Heat Removal Pump Logic (Appendix R to 10 CFR Part 50)	Logic change to eliminate fire-induced failure mechanisms.

Steamflow Recorder	Re-span to encompass new range.
FW Flow Recorder	Re-span to encompass new range.
Turbine 1st Stage Pressure	Recalibrate for revised scram bypass value.
RFPT Speed Control	Modify to support higher pump operational speeds including use of feedwater pump turbine digital speed control.
RFP Low Suction Pressure Trip	Revise setpoints to CPPU values and increase time delay stagger.
RFP Seal Water Injection Temperature	Increase the setpoint of the temperature controller.

These changes will be made to accommodate the revised process parameters. Section 2.4.2 of this SE discusses instrumentation changes covered by TSs. These changes are based on the system review and analysis, which the NRC staff reviewed and documented in Sections 2.5 and 2.8 of this SE. In addition, the licensee will confirm the acceptability of these changes during power ascension testing. Therefore, the NRC staff agrees with the licensee's conclusion that when the above modifications and changes are implemented, SSES Unit 1 and 2 instrumentation and control systems will accommodate the proposed power uprate without compromising safety. Because none of the above changes affects the licensee's compliance with the existing plant licensing basis, SSES Units 1 and 2 will continue to meet the current regulatory basis for the plant.

2.4.2 Instrument Setpoint Methodology

With this LAR, the licensee has requested TS changes associated with instrument setpoint or allowable values related to APRM flow-biased reactor trip for both two-loop and single-loop operation and MSL isolation on high flow. The licensee in its letter dated June 1, 2007, stated that none of these instruments performs a function related to the protection of a TS safety limit (SL). Therefore, these instruments have been identified as limiting safety system setting that are not SL-related, and TS footnotes discussed in NRC Regulatory Issue Summary (RIS) 2006-17, "NRC Staff Position on the Requirements of 10 CFR 50.36, 'Technical Specifications,' Regarding Limiting Safety System Settings during Periodic testing and Calibration of Instrument Channels," dated August 24, 2006, are not needed for the associated TS changes. The licensee's justification for MSL isolation on high flow not being SL-related is based on the use of this instrumentation to provide an isolation signal during an MSLB accident to initiate closure of MSIVs. SSES Unit 1 and 2 FSAR Section 15.6.4.1.2 identifies the MSLB as a "limiting fault" event. FSAR Section 15.0.3.1 defines limiting faults as "occurrences that are not expected to occur but are postulated because their consequences may result in the release of significant amounts of radioactive material." This event is referred to as a "design-basis (postulated) accident." Since the MSL flow—high function is credited only in a DBA event, it is not a variable that protects against violating reactor core safety limits. It is, therefore, not considered an SL-related function. The isolation action, along with the scram function of the reactor protection system (RPS), ensures that the fuel PCT remains below the limits of 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Reactors," and that offsite doses do not exceed the 10 CFR Part 100 limits.

In its safety analysis (PUSAR), the licensee does not take any credit for the APRM simulated thermal power high function (refer to TS Basis for Table 3.3.1.1-1) for SSES Units 1 and 2. The APRM simulated thermal power high function is set above the APRM rod block to provide defense in depth to the APRM fixed neutron high function for certain transients. The accident analysis has taken no specific credit for the APRM simulated thermal power high function.

In its June 1, 2007, RAI response, the licensee provided the basis for the change and the justification for the revised setpoint values. The NRC staff finds the basis and the justification for the changes acceptable. The methodology is based on NEDC-31336P-A, “General Electric Instrument Setpoint Methodology,” which the NRC has previously reviewed and accepted. Also in the June 1, 2007, letter, the licensee provided the clarification and excerpts from the MSL high-flow calculation in response to RAIs from the NRC staff. The staff reviewed the licensee’s setpoint methodology to calculate the nominal trip setpoints, acceptable as left (AAL) band, and acceptable as found (AAF) band for these instruments. The nominal trip setpoint is established at a value which is more conservative than the limiting trip setpoint. The AAL band is established by taking the SRSS of calibration tolerance and vendor accuracy numbers. The AAF value is established by taking the SRSS of calibration tolerance, measurement and test equipment (M&TE) uncertainties, and drift numbers. The licensee’s methodology for calculating these numbers is consistent with the guidance provided in RIS 2006-17 and, therefore, is acceptable to the NRC staff.

The licensee also stated that the instrument channel calibration is performed using approved surveillance procedures which identify the calibration tolerances. Instrument channels are calibrated at the nominal trip setpoint. If during the calibration, instrument channels exceed the AAL band, but are below the acceptable value (AAF band), the instrument will be recalibrated. However, if the instrument is found to be outside the acceptable value (AAF band), it will be calibrated and left within the final tolerance, and an action request will be entered in the corrective action program. The action request is then handled as required by the Action Request and Condition Report Process. Operability and reportability determinations are integral to the corrective action program. The above approach provides an acceptable means to manage instrument setpoints and is consistent with the guidance in RIS 2006-17 and, therefore, is acceptable to the NRC staff.

Based on the preceding, the NRC staff concludes that there is reasonable assurance that the plant will operate in accordance with the safety analysis and that the operability of the instrumentation is assured. Therefore, the NRC staff finds that the proposed changes meet the requirements of 10 CFR 50.36, “Technical Specifications,” and the guidance in RG 1.105, “Setpoints for Safety-Related Instrumentation.”

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 staff concludes that the licensee has adequately addressed the effects of the proposed EPU on these systems and that the changes necessary to achieve the proposed EPU are consistent with the plant’s design basis. The 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, 2, 4, 13, 19, 20, 21, 22, 23, 24, 25, and 29. 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. The NRC staff's review focuses on any increases of fluid volumes that may occur in tanks and vessels as a result of the power uprate. Because the licensee indicated in Sections 10.1.2 and 10.2 of the SSES Unit 1 and 2 PUSAR (Reference 1, Attachment 4) that the fluid volumes in tanks and vessels will not increase following CPPU implementation, an evaluation of this particular area 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 area for processing or disposal while preventing a backflow of water that might result from maximum flood levels to areas of the plant containing equipment that is important to safety. The EFDS also protects against the potential for inadvertent transfer of contaminated fluids to an uncontaminated drainage system. The licensee indicated in Section 8.1 of the SSES Unit 1 and 2 PUSAR (Reference 1, Attachment 4) that EFDS operation and equipment performance are not affected by the proposed power uprate and that no significant increase in total liquid or solid volume will result from operation at uprated conditions. Therefore, 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 as the result of any increases that may be necessary in the pumping capacity of the circulating water pumps or in the sizing of the circulating water piping. Because no changes of this nature are being made for the proposed power uprate, an evaluation of 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 HP system ruptures. Potential missile sources include pressurized systems and components and high-speed rotating machinery. The purpose of the NRC staff's review is to confirm that (1) SSCs important to safety are protected from internally generated missiles and (2) the failure of SSCs not important to safety as the result of missiles will not pose a challenge to SSCs that are important to safety. The NRC staff's review for proposed power uprates focuses on system modifications and increases in system pressures that are necessary and component overspeed considerations that may affect the impact that missiles could have on SSCs important to safety. The criteria that are most applicable to the review of the protection of SSCs important to safety from the effects of internally generated missiles for proposed power uprates are based on GDC 4, insofar as SSCs important to safety should be protected from the effects of internally generated missiles, and other applicable licensing-basis considerations. The NRC staff conducted its review related to internally generated missiles in accordance with the guidance in Section 2.1 of RS-001, Matrix 5, and judged acceptability for CPPU operation on the basis of conformance with existing licensing-basis considerations as discussed primarily in Section 3.5 of the SSES Unit 1 and 2 UFSAR, except where proposed changes are found to be acceptable based on the specified review criteria.

Technical Evaluation

In Sections 7.1 and 10.10 of the SSES Unit 1 and 2 PUSAR, the licensee evaluated the impact of the CPPU on the effects of internally generated missiles that may result from failures in high-energy systems and overspeed of rotating equipment. The licensee determined that the CPPU does not result in any condition (e.g., system pressure increase or equipment overspeed) that would cause the consequences of internally generated missiles to be more severe. The licensee found that the large massive rotating components, such as ECCS pumps and motors, fans, and compressors outside the primary containment, do not have sufficient energy to move the masses of their rotating parts through the housings in which they are contained. In addition, the licensee indicated in Section 10.10 of the SSES Unit 1 and 2 PUSAR that, in regards to pressurized component failures, the CPPU does not affect missiles such as valve bonnets, valve stems, temperature detectors, nuts and bolts, blind flanges, SRVs, and MSIV accumulators.

As discussed in Section 7.1 of the SSES Unit 1 and 2 PUSAR, the licensee evaluated the impact of the proposed CPPU on the consequences of postulated turbine missiles. The licensee concluded that because the proposed power uprate does not affect the design limit for turbine overspeed (see Section 2.5.1.2.2 for additional discussion of turbine overspeed protection), the CPPU will not cause the effects of internally generated missiles (outside containment) on SSCs important to safety to be more severe than previously assumed.

Based on a review of the information provided, the NRC staff concluded that the licensee has adequately evaluated and addressed the potential impact of the proposed CPPU on existing considerations and features that are credited for protecting equipment important to safety from the effects of internally generated missiles. The licensee has determined that the CPPU will not cause the effects of internally generated missiles (outside containment) on SSCs important to safety to be more severe than previously assumed, and therefore the staff agrees that SSCs important to safety will continue to be adequately protected from internally generated missiles following CPPU implementation. The NRC staff also agrees that the effects of postulated main turbine missiles are not changed by the proposed power uprate, provided that overspeed of the main turbines during CPPU operation will not exceed the overspeed limit that was previously established. Section 2.5.1.2.2 of this SE describes the NRC staff's review of main turbine overspeed considerations, which are not within the scope of this section.

Conclusion

The NRC staff has reviewed the licensee's assessment of changes in system pressures, configurations, and equipment rotational speeds necessary to support the proposed CPPU and finds that SSCs important to safety will continue to be protected from the effects of internally generated missiles in accordance with licensing-basis assumptions. Therefore, the proposed CPPU is considered acceptable with respect to the protection from internally generated missiles of SSCs important to safety.

2.5.1.2.2 Turbine Generator

Regulatory Evaluation

The large steam turbines of the main turbine generator (TG) sets have the potential for producing large high-energy missiles, especially if the turbines should exceed their rated speed. The NRC staff's review of the TG sets focuses on the effects of the proposed CPPU on the turbine overspeed protection features to confirm that adequate turbine overspeed protection will continue to be maintained. The criteria that are most relevant to the staff's review of the TG for proposed power uprates are based on GDC 4, insofar as SSCs important to safety should be protected from the effects of turbine missiles, and other applicable licensing-basis considerations. The staff reviewed the TG in accordance with the guidance in Section 2.1 of RS-001, Matrix 5, and judged its acceptability for CPPU operation based on conformance with existing licensing-basis considerations as discussed primarily in Sections 3.5.1.3 and 10.2 of the SSES Unit 1 and 2 UFSAR, except where proposed changes are found to be acceptable based on the specified review criteria.

Technical Evaluation

The SSES Unit 1 and 2 HP turbines will be modified to include a design with a new inner cylinder, two new blade carriers, a new rotor, and new blades to increase the target throttle flow margin and flow passing capability. In support of the CPPU, the existing 12-stage HP turbine monoblock rotor is being replaced by an 11-stage monoblock rotor. The existing low-pressure (LP) shrunk-on wheel design turbine rotors are being retained.

The licensee discusses its evaluation of main turbine overspeed for the CPPU in Section 7.1 of the PUSAR. An EHC system, which sends a signal to close the turbine control valves when the speed exceeds 100 percent, provides the primary speed control for the main turbines. A mechanical overspeed trip with a setting of 110 percent provides the normal backup turbine overspeed protection. An electrical overspeed trip with a setting of 112 percent provides the emergency backup main turbine overspeed protection. The main turbine design and vendor-rated overspeed is 125 percent.

The major considerations in the existing turbine overspeed analysis include the increased steamflow rate and residual steam energy contained within the turbine and associated piping and the inertial effects of the rotor train. The rate of steamflow and amount of residual steam energy increase for CPPU conditions, which will tend to cause the speed of the main turbines to increase slightly following a load rejection and turbine overspeed trip. Because the replacement turbine rotors are more massive than the original rotors, the inertial effects will tend to cause the acceleration rate of the main turbines to decrease compared to the acceleration rate of the original main turbines. The licensee determined that the increased inertial effects are a little more predominant and, consequently, no changes were required for the existing main turbine overspeed trip setpoints.

Based on a review of the information provided, the NRC staff finds that the licensee has adequately evaluated and addressed the potential impact of the proposed CPPU on the capability to prevent overspeed of the main turbines. The licensee's evaluation confirmed that the existing main turbine overspeed trip setpoints will continue to prevent the main turbines from exceeding 120 percent of rated speed following the most limiting load rejection event consistent with the turbine missile analyses that have been completed. The licensee's conclusions are consistent with the NRC staff's experience with proposed power uprates where the HP and LP turbine rotors are upgraded to the monoblock design. Therefore, the staff agrees that CPPU operation will not increase the likelihood that the main turbines will exceed the most limiting design-basis speed that is assumed for turbine missile analyses.

Conclusion

The NRC staff has reviewed the licensee's assessment of the impact that the proposed CPPU will have on overspeed protection of the main turbines and finds that the existing overspeed trip setpoints will continue to prevent the main turbines from exceeding the most limiting overspeed conditions that are assumed in the main turbine missile analyses in accordance with licensing-basis assumptions. Therefore, the proposed CPPU is considered acceptable with respect to the TG.

2.5.1.2.3 Turbine Rotor Integrity

Regulatory Evaluation

GDC 4 requires that SSCs important to safety be protected against environmental and dynamic effects, including the effects of missiles that may result from equipment failure. Because turbine rotors have large masses and rotate at relatively high speeds during normal reactor operation, failure of a rotor will lead to excessive vibration of the turbine rotor assembly and may result in the generation of high-energy missiles. Measures taken by the licensee to ensure turbine rotor integrity and reduce the probability of turbine rotor failure satisfy the relevant requirements of GDC 4.

The NRC staff reviewed the effects of the proposed CPPU on the turbine rotor integrity and probability of turbine missile generation at SSES Units 1 and 2. The NRC's acceptance criteria for the turbine generator are based on GDC 4 and relate to protecting SSCs important to safety from the effects of turbine missiles by providing guidance on turbine rotor integrity to minimize the probability of generating turbine missiles. SRP Section 10.2.3 contains the NRC staff guidance for the turbine rotor integrity issue, and SRP Section 3.5.1.3 offers guidance for the turbine missile generation issue.

Technical Evaluation

Turbine Rotor Integrity

In 2003 for SSES Unit 2 and in 2004 for SSES Unit 1, the licensee changed the main turbine internals from a GE monoblock design for both the HP and LP rotors to a Siemens monoblock for the HP rotor and a Siemens shrunk-on wheel design for the LP rotors. The NRC staff noted that the keyway of the shrunk-on wheel has been known to be susceptible to SCC. The monoblock rotor has no keyway and is considered to be less susceptible to SCC than the shrunk-on wheel. The NRC staff asked the licensee to address the potential keyway cracking on the lower pressure turbines at SSES Units 1 and 2.

In its response to the NRC staff's RAI, by letter dated April 13, 2007 (ADAMS Accession No. ML071150113), the licensee stated that the LP rotor replacement was part of a turbine upgrade project implemented to increase electric generation output and improve turbine reliability. The licensee considered and evaluated three LP rotor designs—monoblock rotors, welded barrel rotors, and advanced disk-type shrunk-on wheel rotors. The licensee's evaluation resulted in the selection of the Siemens design that utilizes advanced disk-type shrunk-on wheel LP rotors. The licensee stated that the Siemens LP rotor design is acceptable for the prevention of keyway cracking because the design has incorporated features to prevent SCC in the keyway. The Siemens advanced disk-type design includes several features to prevent SCC: First, two of the three disks have no keyway, and on the third disk, the key is located in a low-temperature zone. Second, higher compressive stresses are induced in the disk hub bore during heat treatment. Third, shot peening of two of the three disks provides a compressive stress on the disk surface. The licensee did not find any reports of SCC occurring in the turbines that have the Siemens advanced disk design.

For the CPPU, the licensee will replace the existing 12-stage HP monoblock rotor by an 11-stage HP monoblock rotor while the existing LP rotors are being retained. In its RAI response, the licensee clarified that the CPPU evaluation of the HP turbine indicated that the flow area of the HP turbine would have to be increased in order to pass the additional CPPU steamflow. This increase in the flow area will be accommodated in the new HP turbine by removing a stage and opening up the flow area of the remaining 11 stages. Therefore, the current HP turbine replacement would be necessary for CPPU implementation. The LP turbines were designed to pass steamflows in excess of 120 percent of OLTP with no generation performance degradation. Therefore, the LP turbines will not require replacement as a result of the CPPU.

The NRC staff was concerned about the structural integrity of the last stages of the low turbine blades and discs that may be affected by the increased steamflow resulting from the CPPU in terms of corrosion on the blade surfaces and SCC at the root of the blades. In its RAI response, the licensee stated that the last stages of the LP turbines were designed for flows higher than the full CPPU conditions. This includes the corresponding slightly higher operating temperatures and pressures. Thus, the increased CPPU steamflow will not affect the structural integrity of the LP turbine blades for the following reasons:

- For CLTP, all nine stages of LP blades, including the airfoil and the roots, were manufactured from 12-percent chromium materials; materials having 12-percent chromium are resistant to corrosion in this application, including the blade surfaces.

- The licensee's contract with Siemens for both CLTP and CPPU steam conditions required that the design for both the rotating and the stationary parts account for SCC. Hence, the Siemens design includes features to account for SCC.

The NRC staff finds that the LP turbine blade and discs are designed to minimize SCC and, therefore, are acceptable.

The NRC staff asked the licensee to address potential excessive vibration of the LP turbines under the CPPU condition. In its RAI response, the licensee stated that Siemens performed both lateral and torsional vibration analyses of the turbine rotors at CPPU conditions. For the LP turbine, there is no mass change, and therefore no change in natural frequencies. For the HP turbine, there is a minor mass reduction resulting from the 11-stage versus the 12-stage design. Both the CLTP and CPPU lateral and torsional analyses identified natural frequencies within the operating range but outside of the operating speed. The licensee will implement the operating restrictions furnished by Siemens to assure operation at speeds other than those within the natural frequency ranges. Both the new and the existing Siemens turbine designs exclude natural frequencies that are coincident with operating resonance frequencies. The NRC staff finds that the licensee has performed vibration analyses of the turbine system and will implement operating restrictions to avoid the natural frequency of the turbine system. The NRC staff concludes that the turbine design has considered the potential vibration problems and, therefore, is acceptable.

In its RAI response dated April 13, 2007, the licensee addressed the guidance in SRP Section 10.2.3, Revision 1, to demonstrate the rotor integrity of Unit 1 and Unit 2 HP and LP turbines. Each SRP topic is addressed as follows:

- Materials Selection—The selection of materials for both the HP and LP rotors is based on a finite-element analysis and successful operating experience with the rotor materials. The CPPU HP rotors and the CLTP HP rotors use the same material.

- Fracture Toughness—This is determined using Siemens specifications. For both the HP monoblock rotors and the LP shrunk-on disk rotors, the licensee reviewed all disk and rotor properties and confirmed that they were within Siemens specification limits.

- Preservice Inspection—The Siemens quality steam turbine (QST) plan details all of the preservice inspection requirements. The licensee reviewed and approved the Siemens QST. Contained in the CLTP QST are the actual material properties for all rotors and LP disks. Overspeed testing of the two CLTP HP rotors and all six CLTP LP rotors was performed at 125 percent of running speed. The 125 percent represents testing 5 percent above the 120 percent speed used in the turbine missile analysis as the highest expected speed. The CPPU QST plan contains the 125-percent overspeed test requirement for the HP rotors.

- Turbine Disk Design—The design complies with Siemens design procedures. Neither the CLTP HP monoblock rotors nor the CPPU HP monoblock rotor design has separate disks.

- Inservice Inspection—The requirements for the CPPU will be the same as those for CLTP. Hence, the CLTP inservice inspection requirements currently described in SSES FSAR Section 10.2.3.6.a will not change for the CPPU.

On the basis of the above evaluation, the NRC staff concludes that the licensee has demonstrated that the CPPU will not adversely affect the structural integrity of the HP and LP turbines.

Turbine Missile Generation Probability

SRP Section 3.5.1.3 defines the probability of unacceptable damage resulting from turbine missiles (P4) as the product of P1, the probability that a main turbine missile will be generated, P2, the probability that a missile will strike a barrier that houses a critical plant component, and P3, the probability that a missile will breach the barrier and damage a critical plant component (i.e., P4 = P1 x P2 x P3). As shown in SRP Section 3.5.1.3, the NRC staff has focused its guidance on limiting P1 to specific values so that P4 would be within 1×10^{-7} per year per plant.

By letter dated April 13, 2007, the licensee stated that according to the GE licensing topical report NEDC-3304P-A (CLTR), Section 7.1, a separate rotor missile analysis is not required for plants with integral wheels. At the time of the turbine modification, the turbine missile licensing basis was changed to the CLTP turbine missile licensing basis, which is the methodology specified in NUREG-1048, “Safety Evaluation Report Related to the Operation of Hope Creek Generating Station,” Supplement 6, Appendix U, issued July 1986.

The licensee stated that the missile analysis for this replacement is supported by the Siemens Technical Report CT-27332, Revision 2, “Missile Probability Analysis For Siemens 13.9m2 Retrofit Design of Low-Pressure Turbine," which the NRC approved on March 30, 2004. This methodology is the same as the CLTP turbine missile licensing basis with only slight revision. The licensee has confirmed that the eight parameters listed in Section 4.0 of the NRC staff’s SE of the topical report are the same as those used in the SSES Unit 1 and 2 specific missile analysis. The licensee has also confirmed, by reviewing material certificates for the six LP rotors and discs, that the plant-specific parameters listed in Section 3.2.2 of the NRC staff’s SE of the topical report are within the design range of these parameters.

The licensee determined that results of the revised missile analysis indicate that the missile probabilities for P1 are virtually unchanged from the CLTP to the CPPU and are 3.0×10^{-6} per year per unit. This value remains below the limit specified in SRP Section 3.5.1.3 of 1×10^{-5} per year for an unfavorably oriented unit. The CPPU analysis is based on up to 100,000 operating hours (approximately 12 years) between disc inspections. Since the CLTP inspection frequency of 10 years is not being changed, the actual probabilities are less.

The NRC staff notes that the SSES TG is unfavorably oriented with respect to the reactor building. SRP Section 3.5.1.3 imposes a more stringent limit on P1 for the unfavorably oriented turbine than for the favorably oriented turbine. The NRC staff concludes that under the CPPU conditions, the probability of turbine missile generation by the SSES turbines is within the NRC recommended value of 1×10^{-5} per year as specified in SRP Section 3.5.1.3, and therefore is acceptable.

Conclusion

The NRC staff has reviewed the licensee’s assessment of the effects of the proposed CPPU on the TG and finds that the licensee has adequately accounted for the effects of changes in plant conditions on turbine rotor integrity and turbine missile generation probability. The NRC staff concludes that the TG will continue to maintain its intended function to minimize the probability of generating turbine missiles and will continue to meet the requirements of GDC 4 following implementation of the proposed CPPU. Therefore, the NRC staff finds the proposed CPPU acceptable with respect to the TG at SSES Units 1 and 2.

2.5.1.3 Pipe Failures

The licensee discusses its evaluation of the impact that the CPPU will have on the incidents and consequences of failure of high- and moderate-energy piping located outside containment in Sections 10.1 and 10.2 of the SSES Unit 1 and 2 PUSAR (Reference 1, Attachment 4). The proposed power uprate does not affect the protection of SSCs important to safety from the effects of postulated pipe failures because (1) the reactor dome and system pressures used in the existing HELB analyses are unaffected by the CPPU, (2) no new HELB locations are postulated, and (3) the proposed CPPU has no impact on flooding effects resulting from postulated pipe breaks. Therefore, an evaluation of this area is not required.

2.5.2 Fission Product Control

2.5.2.1 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 CPPU conditions. Consequently, the NRC staff's review focuses primarily on any adverse effects that the proposed CPPU might have on the assumptions used in previously completed analyses. Because Section 2.6, Containment Review Considerations, Section 2.7, Habitability, Filtration, and Ventilation, and Section 2.9, Source Terms and Radiological Consequences, of this SE address the impact of the CPPU on plant systems and structures identified by the licensee as making up the fission product control system, a separate evaluation in this section is not required.

2.5.2.2 Main Condenser Evacuation System

The main condenser evacuation system (MCES) is a nonsafety-related system used for establishing a vacuum in the condenser during startup and for maintaining the vacuum during normal plant operation. It also removes the noncondensable gases from the main condenser and air ejectors during normal operation and discharges these gases to the gaseous radwaste system. The MCES is sized based on the volume of the condenser and desired evacuation time, neither of which is impacted by the proposed uprate. Consequently, the existing capability to monitor the MCES effluent is also unaffected by the proposed CPPU, and an evaluation of the MCES is not required.

2.5.2.3 Turbine Gland Sealing System

The turbine gland sealing system (TGSS) is a nonsafety-related system that provides sealing steam for the main turbine shafts, the RFPTs, and selected valve stem packing to prevent air in-leakage and the escape of steam, thereby preventing the uncontrolled release of radioactive material in the steam to the environment. Because no significant modifications are being made to the TGSS and noncondensable gases will continue to be monitored for radiation, the proposed power uprate will not adversely affect the function of the TGSS. Therefore, an evaluation of the TGSS is not required.

2.5.2.4 Main Steam Isolation Valve Leakage Control System

Because SSES Units 1 and 2 do not have an MSIV leakage control system, this review section is not applicable.

2.5.3 Component Cooling and Decay Heat Removal

2.5.3.1 Spent Fuel Pool Cooling

Regulatory Evaluation

The spent fuel pool (SFP) provides wet storage of spent fuel assemblies. The design function of the fuel pool cooling system (FPCS) 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 of the FPCS for proposed power uprates focuses on the capability of the system to provide adequate cooling to the spent fuel during all operating and accident conditions. The criteria that are most applicable to the NRC staff's review of the FPCS for proposed power uprates are based primarily on GDC 61, insofar as it requires that fuel storage systems be designed with residual heat removal capability reflecting the importance to safety of decay heat removal (DHR), and other applicable licensing-basis considerations. The staff reviewed the FPCS in accordance with the guidance in Section 2.1 of RS-001, Matrix 5, and judged the acceptability for CPPU operation based on conformance with existing licensing-basis considerations as discussed primarily in Section 9.1.3 of the SSES Unit 1 and 2 UFSAR, except where proposed changes are found to be acceptable based on the specified review criteria.

Technical Evaluation

The licensee evaluated the FPCS in Section 6.3.1 of the SSES Unit 1 and 2 PUSAR. SSES Units 1 and 2 each have an SFP. The SFPs are centrally located between the two reactors and share a common cask storage pit. Each SFP has its own cooling system, which consists of three parallel heat exchangers and three pumps. The SFP gates normally separate each SFP from its respective reactor cavity.

The current licensing basis for the SSES Unit 1 and 2 FPCS is to maintain the SFP bulk water temperature below 125 °F for a normal batch offload (approximately 342 fuel assemblies), assuming that the assemblies are offloaded to the SFP within 160 hours after shutdown, and to maintain the SFP bulk water temperature below 125 °F for abnormal (i.e., full-core) offload conditions operating with supplemental cooling from the RHR system operating in the fuel pool cooling mode with one RHR pump and heat exchanger available for SFP cooling. Also, Section 9.1.3.3 of the SSES Unit 1 and 2 UFSAR indicates that the emergency service water system (ESWS) is relied on as a seismic Category 1 source of SFP makeup water and states that the design makeup rate from each ESWS loop is based on replenishing the postulated boiloff from the maximum normal heat load in each SFP for 30 days following a loss of the FPCS.

As a result of the proposed CPPU, the normal and abnormal SFP heat loads will be higher than the pre-uprate heat loads because of increased decay heat. To assure adequate SFP cooling for CPPU conditions, the licensee performed analyses for batch and full-core offload scenarios. The SSES Unit 1 and 2 PUSAR (Reference 1, Attachment 4, Section 6.3.1) discusses the results of these analyses, and PUSAR Tables 6-4 and 6-5 summarize some of the assumptions, inputs, and results. For both offload cases, the licensee assumed that the SFP heat exchangers for the unit being refueled are cooled by 75 °F river water, whereas the service water temperature is allowed to be as high as 95 °F. Because the cooling water temperature used in the CPPU analyses for SFP cooling was significantly lower than the maximum allowed service water temperature, the NRC staff requested, by letter dated April 16, 2007 (Reference 41), that the licensee justify this apparently nonconservative assumption. In a letter dated May 14, 2007 (Reference 40, response to NRC Question 1), the licensee stated that the value of 75 °F was chosen based on the river water temperature that typically exists during spring (March) when the refueling outages are usually scheduled. The licensee also clarified that the 75 °F river water temperature is not an actual limit, but rather a conservative assumption used for the purposes of licensing-basis analyses, and that plant procedures govern the actual limits for a particular outage.

In consideration of the additional information provided in the May 14, 2007, letter, the NRC staff noted that the SSES Unit 1 and 2 licensing basis relative to SFP cooling, as reflected in the UFSAR description, does not detail the administrative controls that are relied on to ensure that the SFP cooling capability will not be exceeded. Consequently, the staff requested that the licensee discuss the measures taken to assure that the cooling capability of the FPCS will not be exceeded following CPPU implementation in accordance with the SSES Unit 1 and 2 licensing basis. The licensee responded to this request in Attachment 3 of its letter dated July 13, 2007 (Reference 34, response to NRC Question 1). The licensee stated that the fundamental licensing requirements related to SFP cooling are to (1) maintain the SFP bulk temperature below 125 °F and (2) maintain a time to boil of at least 25 hours when a seismic Category 1, Class 1E cooling system is not assisting in SFP cooling. The licensee indicated that outage-specific calculations are performed to ensure that the RHR fuel pool cooling mode is not secured until the decay heat load of the SFP is within the design cooling capability of the FPCS and the time to boil exceeds 25 hours with an SFP bulk temperature that is less than or equal to an administrative limit of 115 °F. The licensee also indicated that, to ensure the administrative limits can be maintained, the calculations, which are mandated by plant procedures, assume makeup and service water temperatures that are slightly higher than the actual temperatures expected during the outage.

Although the proposed CPPU will result in an increase in the SFP heat loads, the licensee determined that the proposed power uprate will not affect the capability to establish alternate cooling or makeup to the SFP following a complete loss of the nonseismic FPCS. Specifically, the 25-hour time to boil that is maintained when the RHR system is not aligned to provide SFP cooling will continue to afford plant operators sufficient time to align one train of the RHR system in the SFP cooling mode to prevent boiling from occurring in the SFP. The licensee also confirmed that the ESWS excess flow capacity that is available for emergency SFP makeup will continue to satisfy licensing-basis considerations. In particular, the licensee indicated that the 70–gallon-per-minute (gpm) ESWS flow rate (35 gpm for each SFP) that is available for emergency SFP makeup will continue to be capable of compensating for water that is lost because of boiloff and evaporation to maintain at least 23 ft of water above the fuel at all times following CPPU implementation.

Based on its review of the information provided, the NRC staff concludes that the licensee has adequately evaluated and addressed the potential impact of the proposed power uprate on the capability of the FPCS, with the assistance of the RHR system operating in the fuel pool cooling mode, to accommodate the increased SFP heat load. The licensee has determined that existing administrative controls will continue to ensure that the plant licensing basis relative to SFP cooling and time to boil will be maintained during CPPU operation. The licensee has also confirmed that the emergency SFP makeup capability that is afforded by the ESWS will continue to be adequate for CPPU operation. Therefore, the NRC staff agrees that the capability to remove decay heat from the SFP following normal and full core offloads and to provide sufficient makeup to the SFP will be maintained in accordance with plant licensing-basis considerations following CPPU implementation.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the impact that the proposed CPPU will have on the FPCS and finds that the FPCS will continue to be capable of performing its cooling function and that the SFP makeup capability will continue to be adequate in accordance with licensing-basis considerations. Therefore, the staff considers the proposed CPPU to be acceptable with respect to SFP cooling and makeup capability.

2.5.3.2 Station Service Water System

Regulatory Evaluation

The station service water system (SWS) provides essential cooling for safety-related equipment and may also provide cooling for nonsafety-related auxiliary components that are used for normal plant operation. The NRC staff's review of proposed power uprates focuses on the impact that the proposed CPPU will have on the capability of the SWS to perform its safety functions. The criteria most applicable to the staff's review of the SWS for proposed power uprates are based primarily on 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 other applicable licensing-basis considerations. The NRC staff reviewed the SWS in accordance with the guidance in Section 2.1 of RS-001, Matrix 5, and judged its acceptability for CPPU operation based on conformance with existing licensing-basis considerations as discussed primarily in Sections 9.2.5 and 9.2.6 of the SSES Unit 1 and 2 UFSAR, except where proposed changes are found to be acceptable based on the specified review criteria.

Technical Evaluation

Section 6.4.1 of the SSES Unit 1 and 2 PUSAR provides the licensee's evaluation of the SWS for CPPU operation; discussion of GL 96-06, "Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions," dated September 30, 1996, appears in PUSAR Section 4.1.6. The safety-related SWS includes both the ESWS and the residual heat removal service water system (RHRSWS). The ESWS removes heat from HVAC coolers, EDG coolers, ECCS components, and other equipment required to operate during normal or accident conditions. The ESWS also provides makeup water to the SFP in the event of a complete loss of SFP cooling capability. The RHRSWS is relied on for removing reactor core decay heat during normal or emergency conditions. Based on its evaluation, the licensee determined that the following heat loads are not significantly impacted by changes in reactor thermal power:

- EDG coolers
- RHR and CS pump room coolers
- HPCI and RCIC pump room coolers
- RHR pump motor coolers
- control structure chiller condenser

- Unit 2 emergency switchgear room cooling

The licensee found that the analyses performed for CLTP operation bounded the effects of the proposed CPPU on the capability of the ESWS heat exchangers to accommodate the additional CPPU heat loads. Additionally, the licensee indicated that after the necessary spray pond modifications are completed (discussed in Section 2.5.3.4), postmodification flow testing will be performed before CPPU implementation to confirm that ESWS flow rates are as expected for the worst-case alignment. Relative to RHRSWS performance, the licensee determined that although the post-LOCA RHR heat load will increase because of an increase in the maximum suppression pool temperature that occurs following a LOCA, the licensee concluded that the cooling capability of the RHRSWS is adequate to maintain the suppression pool temperature within acceptable design limits following a LOCA at the proposed uprated power level. The licensee also determined that the RHRSWS is capable of providing adequate cooling and that the ESWS is capable of providing adequate makeup for the SFP and that the RHRSWS has sufficient capacity for long-term core and containment cooling at the proposed power uprate conditions. Finally, the licensee confirmed that the programmatic controls established in response to GL 89-13, “Service Water System Problems Affecting Safety-Related Equipment,” dated July 18, 1989, and that the resolution of GL 96-06 will continue to be adequate for CPPU operation.

Based on a review of the information submitted, the NRC staff finds that the licensee has adequately evaluated and addressed the impact of the proposed CPPU on the capability of the safety-related SWS (i.e., ESWS and RHRSWS) to perform its safety functions. Because design limitations of SSCs will not be exceeded and licensing-basis considerations will continue to be satisfied, the NRC staff agrees that the proposed power uprate will not impact the capabilities of the SWS. Additionally, existing GL 89-13 programmatic controls will continue to assure that heat exchanger performance is maintained consistent with licensing-basis considerations following implementation of the proposed power uprate, and the proposed power uprate will not affect the licensee’s resolution of the GL 96-06 water hammer and two-phase flow issues.

Conclusion

The NRC staff has reviewed the licensee’s assessment of the impact that the proposed CPPU will have on the safety-related portion of the SWS (i.e., the ESWS and RHRSWS) and finds that the SWS will continue to be capable of performing its safety functions in accordance with licensing-basis considerations. Therefore, the proposed power uprate is considered acceptable with respect to the SWS.

2.5.3.3 Reactor Auxiliary Cooling Water Systems

The NRC staff’s review covers reactor auxiliary cooling water systems (RACWSs) that are required for (1) safe shutdown during normal operations, AOOs, and mitigation of the consequences of accident conditions or (2) prevention of accidents. The RACWS for SSES Units 1 and 2 include the reactor building closed cooling water system and the turbine building closed cooling water system. These systems transfer heat from systems and components in the reactor, radwaste, and turbine building during normal operation, but have no safety function. Therefore, NRC evaluation of the RACWS is not required.

2.5.3.4 Ultimate Heat Sink

Regulatory Evaluation

The UHS provides the safety-related cooling medium required to dissipate heat removed from the reactor and its auxiliaries during normal operation, refueling, and accident conditions. The UHS for SSES Units 1 and 2 is an 8-acre, 25-million-gallon seismic Category 1 spray pond that provides cooling water to the ESWS and the RHRSWS during normal shutdown and following design-basis accidents. The spray pond consists of two spray divisions, each with a large and small spray array for dissipating heat. The NRC staff's review of the UHS for proposed power uprates focuses on the impact that the proposed uprate will have on the capability of the UHS to perform its safety functions. The staff also reviews the UHS design-basis temperature limit determination to confirm that postlicensing data trends (e.g., air and water temperatures, humidity, windspeed, and water volume) do not establish more severe conditions than previously assumed. The criteria that are most applicable to the NRC staff's review of the UHS for proposed power uprates are based on GDC 44, insofar as it requires 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 applicable licensing-basis considerations. The NRC staff reviewed the UHS in accordance with the guidance in Section 2.1 of RS-001, Matrix 5, and judged the acceptability for CPPU operation based on conformance with existing licensing-basis considerations as discussed primarily in Section 9.2.7 of the SSES Unit 1 and 2 UFSAR, except where proposed changes are found to be acceptable based on the specified review criteria.

Technical Evaluation

The licensee's evaluation of the UHS appears in Section 6.4.5 of the SSES Unit 1 and 2 PUSAR, as supplemented by letters dated May 14, 2007 (Reference 40, response to NRC Question 4), July 13, 2007 (Reference 34, response to NRC Question 4), and August 28, 2007 (Reference 42). The licensee stated that the decay heat load used in the UHS performance analysis was calculated using ANSI/American Nuclear Society (ANS) 5.1-1979 with a two-sigma uncertainty instead of the decay heat uncertainty calculation method described in BTP 9-2. The licensee also determined that modifications are necessary to increase the heat dissipation capability of the spray pond for CPPU operation. In particular, the licensee is modifying each division of the large spray arrays by capping approximately 44 of the 356 spray nozzles in order to increase the spray nozzle pressure, which in turn will increase the spray height and thus the cooling effectiveness. These modifications are necessary because of increased pond evaporation and drift loss. The licensee is also installing manual valves to provide redundant isolation capability of the spray array bypass lines in order to credit spray arrays in both divisions for heat removal. The current design provides only a single MOV for this isolation purpose, which makes one spray division vulnerable to single failure. The licensee determined that upon implementation of these modifications, the UHS will be capable of dissipating the additional CPPU heat load in accordance with applicable licensing-basis considerations. The licensee's analysis, which assumed maximum water loss conditions over a 30-day period, included licensing-basis assumptions relative to SFP boiloff and makeup considerations (discussed in Section 2.5.3.1 of this SE).

As discussed in PUSAR Section 6.4.5, the licensee plans to complete postmodification testing after the number of spray nozzles is reduced to confirm that the large spray array flow rates are consistent with analytical assumptions. The licensee indicated that the minimum required flow rate is based on correlations that exist for nozzle flow rate versus spray height to assure that the actual spray height is greater than or equal to analytical assumptions. Because performance of the spray nozzles can vary over time depending on the amount of wear, the NRC staff requested (Reference 41) that the licensee explain how it will account for aging effects to assure conservative results. The licensee's response (Reference 34, response to NRC Question 4) indicated that the correlation between spray height and nozzle pressure is based on vendor information and bench test data points obtained when the SSES nozzles were originally purchased. During the period that the nozzles have been in service, the licensee has performed periodic inspections and maintenance on the spray arrays and has identified no indications of flow-induced erosion or degradation of the nozzles. To provide additional confirmation that erosion and degradation of the nozzles have not occurred, the licensee inspected a representative sample of the spray nozzles from both of the large spray array divisions. In all cases, the licensee found that the spray nozzle orifices inspected were clean and smooth and without any signs of degradation.

The new spray array bypass line manual isolation valves will be installed per ASME Code Section III, Class 3 requirements, and will satisfy the applicable licensing-basis criteria for SSES Units 1 and 2. Each valve will be installed in an existing missile-protected valve vault that contains no high-energy piping and will be capable of being operated from outside the vault with the use of a reach rod and a detachable valve handle that will be staged in a specified location easily accessible by the plant operators. Visual observation will readily identify local flow through the lines. The licensee proposes to establish TS requirements for the manual bypass valves that are being installed and credited for isolating the spray array bypass line if the MOV in the spray array bypass line fails open. The NRC staff's evaluation of this proposed change to the SSES Unit 1 and 2 TS requirements appears below.

For current plant operation, failure of an existing spray array bypass valve to close is the worst-case single active failure for the UHS. The failure of a spray array bypass valve to close causes the affected spray division to be bypassed, while the unaffected spray division dissipates heat via the unaffected large spray array nozzles. Consequently, the current licensing basis assumes that no spray cooling takes place in the affected spray division and that the heat from the affected division is transferred directly to the UHS water volume pending operator action to manage the heat loads in accordance with plant procedures. Operator action is relied on to minimize the heat loads on the affected division to keep the spray pond temperature from exceeding the maximum allowed value, and no credit is taken for reestablishing spray flow on the affected spray division.

For the uprated plant, because the installation of manual spray array bypass line isolation valves will enable the plant operators to isolate the spray array bypass lines for both spray divisions, the licensee determined that the worst-case single failure for CPPU conditions becomes the failure of the large spray array isolation valve for one spray division to open. In this case, the licensee credits the ability of reactor operators to open the small spray array isolation valve on the affected division, as specified in plant procedures, in order to dissipate heat through the small spray array on one division, while also dissipating heat through the large spray array on the other division. The licensee proposed to establish TS requirements for the small spray array isolation valves since they are being credited to help dissipate heat following CPPU implementation if the large spray array isolation valve in the same division fails to open. The NRC staff's evaluation of this proposed change to the SSES Unit 1 and 2 TS requirements appears in Section 2.5.3.4.1 below.

Based on a review of information provided by PPL as part of its UHS analysis using ANSI/ANS 5.1-1979, the NRC staff finds that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the UHS to perform its safety functions. Because the inventory of the UHS will continue to be adequate for long-term DHR and concurrent SFP makeup, and because the maximum allowed temperature of the UHS will not be exceeded as a result of the proposed power uprate, the NRC staff agrees that the UHS will continue to be capable of performing its safety functions consistent with licensing-basis considerations following CPPU implementation.

With the exception of the use of ANSI/ANS 5.1-1979 instead of BTP 9-2 for decay heat calculations, the use of the revised single active failure considerations associated with spray array bypass flow and use of the small spray array for dissipating heat, and analytical assumptions relative to spray nozzle performance characteristics, the licensee has not proposed any other changes to the plant licensing basis that are within the scope of this evaluation. Consequently, this evaluation does not constitute NRC review and approval of any other changes to the plant licensing basis relative to the UHS.

Conclusion

The NRC staff has reviewed the licensee's assessment of the impact that the proposed CPPU will have on the UHS and finds that the UHS will continue to be capable of performing its safety function in accordance with licensing-basis considerations. Therefore, the proposed power uprate is considered acceptable with respect to the UHS.

2.5.3.4.1 Proposed Changes to TS 3.7.1, "Residual Heat Removal Service Water (RHRSW) System and the Ultimate Heat Sink (UHS)"

Regulatory Evaluation

The safety-related UHS for SSES Units 1 and 2 consists of a shared spray pond for both units, which includes two independent spray loops (or divisions) that are also shared. Each of the spray array divisions consists of one large and one small spray array. The UHS is relied on for providing enough cooling water at less than or equal to the maximum allowed temperature of 97 °F for at least 30 days of postaccident cooling, consistent with the plant licensing basis. The spray arrays are relied on for dissipating the design-basis heat load without exceeding the maximum allowed water temperature. Consistent with the UHS analyses completed for CPPU operation (discussed in Section 2.5.3.4), the licensee proposed changes to TS 3.7.1 that would (1) add the small spray array isolation valves to Table 3.7.1-1, "Ultimate Heat Sink Spray Cooling Large Array Valves," as components that must be operable in order to meet Limiting Condition for Operation (LCO) 3.7.1 and, consistent with this change, retitle Table 3.7.1-1, "Ultimate Heat Sink Spray Array Valves," (2) add a new Table 3.7.1-3, "Ultimate Heat Sink Spray Array Bypass Manual Valves," to specify that the two newly installed manual isolation valves for the two spray divisions are components that must be operable, (3) revise the LCO for TS 3.7.1 to allow under Condition A any combination of the valves listed in TS Tables 3.7.1-1, 3.7.1-2, or 3.7.1-3 that are in the same spray division to be inoperable, and (4) add Required Action A.3 and completion time to establish an open flowpath in the affected spray division within 8 hours whenever a spray division valve is inoperable.

The requirements and criteria that are most applicable to the licensee's proposed changes to TS 3.7.1 are 10 CFR 50.36(c)(2)(ii)(C), insofar as it specifies that TS requirements be established for components that are relied on for mitigating design-basis accidents or transients; GDC 44, insofar as it requires 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 applicable licensing-basis considerations. Acceptability of the proposed TS changes is judged based on compliance with applicable NRC regulations, consistency with NRC policy as reflected by the Standard Technical Specifications (STS), and conformance with existing licensing-basis considerations as discussed primarily in Section 9.2.7 of the SSES Unit 1 and 2 UFSAR.

Technical Evaluation

As discussed in Section 2.5.3.4, the licensee has determined that UHS modifications are necessary to increase the heat dissipation capability of the spray pond for CPPU operation. Among other things, the licensee is installing manual valves to provide redundant isolation capability of the spray array bypass lines so the spray arrays in both divisions can be credited for heat removal. The licensee has determined that this particular plant modification will provide additional operational flexibility and significantly reduce operator burden by allowing both spray divisions to be credited for accident mitigation and DHR. Because the current design provides only a single MOV for isolating each of the spray array bypass lines, a failure of one of these valves would render its associated spray division inoperable. Installation of an additional isolation valve in each of the spray array bypass lines will eliminate this single-failure vulnerability.

The licensee has determined that upon installation of the manual spray array bypass isolation valves, the worst-case single failure relative to UHS operation is failure of a large spray array supply valve to open. For this and other component failure scenarios, the plant operating procedures instruct the plant operators on how to align the heat loads and spray arrays to ensure that accident analyses and system design limitations will not be exceeded. While installation of the spray array manual bypass valves will allow both spray divisions to be credited for heat removal, the licensee indicated that the UHS analyses for CPPU operation demonstrate that one spray division will continue to be adequate for mitigating an accident on one unit while the other unit is concurrently shutting down and cooling.

To credit the use of both spray divisions in a manner consistent with the UHS analysis for CPPU operation, the licensee has proposed changes to TS 3.7.1 as discussed in the preceding Regulatory Evaluation section. The proposed TS changes are evaluated below.

a. Proposed Change To Add the Small Spray Array Isolation Valves to Table 3.7.1-1 as Components That Must Be Operable in Order To Meet LCO 3.7.1

The small spray array is not credited in the current UHS thermal analysis, and therefore, there was no need to establish TS requirements for the small spray array supply isolation valves for CLTP operation. However, in the UHS thermal analysis completed for CPPU operation, the licensee does credit use of the small spray array to dissipate heat in the event that the large spray array supply isolation valve associated with the same spray division fails to open. Failure of the large spray array isolation valve to open requires plant operators to reduce the RHRSWS flow within 3 hours of event initiation for the affected division, when the redundant RHRSWS pump can be secured. Reduction of RHRSWS flow will allow the small spray array to operate within its design capacity. For the first 3 hours immediately following event initiation and before alignment of the small spray array to dissipate the reduced heat load, flow for the affected division is through the spray array bypass line. Starting at 3 hours, the small spray array isolation valve is opened from the control room, and the spray array bypass line is isolated to direct flow through the small spray array and dissipate heat in the spray division with the inoperable large spray array supply isolation valve. Given these considerations, the licensee's analysis of the UHS for CPPU operation indicates that the UHS temperature limit of 97 °F will not be exceeded for the worst-case scenario in accordance with the plant licensing basis.

The small spray array isolation valves are credited for mitigating accident conditions during CPPU operation, and in accordance with the provisions of 10 CFR 50.36, it is appropriate and necessary to establish TS requirements for these valves. The required actions and completion times that are proposed for the small spray array isolation valves are the same as those that apply to the large spray array isolation valves, which perform the same function. The proposed actions and completion times are also consistent with those specified by the STS in that the affected spray division either remains capable of performing its assigned functions while in this condition or the allowed completion time is reduced accordingly. Therefore, because the TS actions and completion times proposed for the small spray array isolation valves are consistent with those that have been approved for the large spray array isolation valves, and because they are consistent with NRC policy as reflected in the STS, the NRC staff considers the proposed TS actions and completion times for the small spray array isolation valves to be acceptable.

b. <u>Proposed Change To Add Manual Spray Array Bypass Valves to New TS Table 3.7.1-3 as Components That Must Be Operable in Order To Meet LCO 3.7.1</u>

As discussed in Section (a), to credit the cooling capability of a small spray array, a manual isolation valve is being installed in the bypass line for each spray division to address the postulated failure of a spray array bypass line motor-operated isolation valve to close. Consequently, the newly installed manually operated isolation valves for the spray divisions are credited for mitigating accident conditions during CPPU operation, and in accordance with the provisions of 10 CFR 50.36, it is appropriate and necessary to establish TS requirements for these valves. The required actions and completion times proposed for the manual isolation valves for the spray division bypass lines are the same as those that apply when the spray division bypass line motor-operated isolation valves, which perform the same function, are inoperable. The proposed completion times and actions are also consistent with those specified by the STS in that the affected spray division either remains capable of performing its assigned functions while in this condition or the allowed completion time is reduced accordingly. Therefore, because the TS completion times and actions proposed for the spray division bypass line manual isolation valves are consistent with those that have been approved for the motor-operated isolation valves that perform the same function, and they are consistent with NRC policy as reflected in the STS, the NRC staff considers the proposed TS requirements for the spray array bypass line manual isolation valves to be acceptable.

c. <u>Proposed Change To Allow Any Combination of Valves Listed in Table 3.7.1-1, Table 3.7.1-2, or Table 3.7.1-3 That Are in the Same Spray Array Division To Be Inoperable for Up to 72 Hours Provided the Associated RHRSW System Is Immediately Declared Inoperable</u>

In addition to the existing and proposed required actions and completion times for specific valves associated with the spray array divisions, the licensee proposed to modify TS 3.7.1.A to allow any combination of the valves listed in TS Tables 3.7.1-1 through 3.7.1-3 associated with the same spray division to be inoperable under the same required actions and completion times that apply when individual spray division valves are inoperable. The proposed requirement is similar to the requirement that currently exists for multiple inoperable valves in a single spray division but is modified to include the new valves that are being credited for CPPU operation. The existing TS requirement was justified because a single spray division is capable of dissipating the maximum assumed heat load, and either one spray division remains operable when in this condition or the TS requires the specified completion time to be reduced accordingly. Because the licensee's thermal UHS analysis confirms that a single spray division will continue to be capable of dissipating the maximum assumed heat load for the proposed power uprate in accordance with licensing-basis considerations, the existing TS requirement which allows multiple valves in a single spray division to be inoperable remains valid. The proposed completion times and actions are also consistent with those specified by the STS, in that the affected spray division either remains capable of performing its assigned functions while in this condition or the allowed completion time is reduced accordingly. Therefore, because the TS completion times and actions that are proposed for multiple inoperable valves in a single spray division are consistent with those that were approved previously for this condition and because they are consistent with NRC policy as reflected in the STS, the NRC staff considers the proposed TS requirements for multiple inoperable valves in the same spray division to be acceptable.

d. Proposed Change To Add a Required Action To Establish an Open Flowpath within 8 Hours of Declaring a Spray Division Valve or Multiple Valves in the Same Spray Division Inoperable

The licensee proposed to add Required Action A.3 to establish an open return flowpath to the spray pond within 8 hours of declaring a single valve or multiple valves in the same spray division inoperable. The ESWS provides cooling water for critical plant equipment (such as the EDGs), and the cooling water is returned to the spray pond via the same two spray divisions that form the return flowpaths for the RHRSWS. A required return flowpath can be established by placing operable or inoperable valves in a given flowpath (i.e., large spray array, small spray array, or spray array bypass line) in the open position with power removed (as applicable), provided that the action is consistent with existing operational limitations such as minimum and maximum temperature considerations. Because the UHS spray division flowpaths are necessary for the ESWS to perform its safety functions in accordance with accident analysis assumptions, it is appropriate and necessary to establish TS requirements for restoring and assuring the operability of the spray division flowpaths in accordance with the provisions of 10 CFR 50.36. The proposed completion time of 8 hours is consistent with the time that has been approved for restoring inoperable spray division valves when an RHRSWS subsystem associated with the unaffected spray division is found to be inoperable with a similar condition. One inoperable spray division valve (or multiple inoperable valves associated with the same spray division) could cause the one operable ESWS division return flowpath to be inoperable. The proposed completion time is consistent with those specified by the STS in that the proposed time is much less than the 72 hours typically allowed when one safety division remains operable. Therefore, because proposed TS Action A.3 is considered necessary in accordance with 10 CFR 50.36 requirements, and because the proposed completion time is consistent with existing SSES Unit 1 and 2 TS requirements and is also consistent with NRC policy as reflected in the STS, the NRC staff considers the proposed TS action and completion time to be acceptable.

2.5.4 Balance-of-Plant Systems

2.5.4.1 Main Steam

The main steam supply system (MSSS) transports steam from the reactor to the power conversion system (PCS) and to various auxiliary steam loads. The NRC staff review of the MSSS for proposed power uprates 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 otherwise result in increased challenges to reactor safety systems. Because the licensee is making no changes of this nature for CPPU operation, an evaluation of the MSSS is not required.

2.5.4.2 Main Condenser

The main condenser system (MCS) is designed to condense and deaerate the exhaust steam from the main turbine and provide a heat sink for the turbine steam bypass system (TSBS). The MCS is typically credited for providing sufficient condensate retention time to allow short-lived radioactive isotopes to decay. For BWRs without an MSIV leakage control system, the MCS may also be credited for providing holdup and plate-out of radioactive iodine through the MSIV bypass leakage pathway following core damage. The NRC staff's review for proposed power uprates focuses primarily on any changes being made to the MSIV bypass leakage pathway to confirm that the isolation boundary has been properly established. Because the proposed CPPU will not result in any changes to the MSIV bypass leakage pathway boundaries, the proposed power uprate does not affect this area of review. Therefore, an evaluation of the MCS is not required.

2.5.4.3 Turbine Steam Bypass System

The TSBS is a nonsafety-related system designed to discharge a stated percentage of rated MS flow directly to the main condenser, bypassing the turbine, which enables the plant to take step-load reductions up to the capacity of the TSBS without causing the reactor or turbine to trip. The NRC staff's review for proposed power uprates focuses primarily on any modifications being made to the TSBS that may warrant the performance of confirmatory testing. Because the licensee is not changing the design and operation of the TSBS for CPPU operation, an evaluation of the TSBS is not required.

2.5.4.4 Condensate and Feedwater System

Regulatory Evaluation

The condensate and FW system (CFS) provides FW at a particular temperature, pressure, and flow rate to the reactor. While the CFS does not perform a safety function, marginal system design and operational capability could result in loss of feedwater (LOFW) transients and increased challenges to safety systems. The NRC staff's review of the CFS for proposed power uprates focuses primarily on system modifications, design limitations, and reductions in operational flexibility that could result in less reliable CFS operation. The acceptance criteria that are most applicable to the NRC staff's review of the CFS for proposed power uprates are based on existing plant licensing-basis considerations, especially with respect to maintaining CFS reliability and minimizing LOFW event occurrences. The staff reviewed the CFS in accordance with the guidance in Section 2.1 of RS-001, Matrix 5, and judged the acceptability for CPPU operation based on conformance with existing licensing-basis considerations as discussed primarily in Section 10.4.7 of the SSES Unit 1 and 2 UFSAR, except where proposed changes are found to be acceptable based on the specified review criteria.

Technical Evaluation

The licensee's evaluation of the CFS for CPPU operation appears in Section 7.4 of the SSES Unit 1 and 2 PUSAR. The licensee determined that CFS operating flows will increase to approximately 114 percent of the current flow rate for CPPU operation. Following implementation of planned CFS modifications, there will be approximately 11.8-percent flow margin for CPPU operation. Some of the more significant planned CFS modifications include:

- replacement of condensate pump impellers with high head pump impellers
- modification of condensate pump minimum flow valves to support higher flow rates
- modification of all three RFP turbines to support higher speeds
- modification of RFP suction pressure trip setpoint and time delay

Upon NRC approval of the proposed power uprate, the licensee plans to implement the increased power level in two phases at Unit 1. The first phase of operation will achieve a power level of 3733 MWt and will include implementation of the modifications referred to above, except for the RFP turbine modifications. As discussed in Attachment 8 of the CPPU request, the licensee plans to trip a condensate pump while operating at this intermediate power level to confirm acceptable performance of the CFS. The licensee determined that tripping a condensate pump bounds the transient conditions that result from the trip of an RFP because the condensate pump trip is expected to cause an RFP to trip because of the low RFP suction pressure that occurs during the transient, whereas the transient response resulting from an RFP trip is not expected to be as severe. However, the licensee plans to perform similar testing at the full CPPU power level of 3952 MWt only if the test results at the lower power level are unacceptable. Since the RFP turbine modifications will still need to be completed and could cause a further reduction in the RFP suction pressure following a trip of a condensate pump, the NRC staff questioned the basis for not performing further testing at the full CPPU power level. To verify that the available NPSH after a trip of either an RFP or condensate pump is sufficient to prevent the other RFPs from tripping on low suction pressure, thereby causing a total LOFW, the staff requested that the licensee (1) confirm that the condensate pump trip bounds the FW pump trip with respect to the most limiting FW pump NPSH response and (2) provide the acceptance criteria and basis for determining if the condensate pump trip test must be repeated at the full CPPU power level, including how the available margin must compare to the required margin, to adequately account for the RFP turbine modifications.

The licensee indicated that the CPPU analysis shows that a condensate pump trip results in a minimum RFP suction pressure of 248 psig, compared to a minimum suction pressure resulting from an RFP trip of 399 psig (Reference 34, response to NRC Question 5). The trip setpoint corresponding to the minimum required NPSH for the RFPs is 285 psig, with nominal trip time delays for CPPU operation of 5 seconds, 15 seconds, and 30 seconds for RFPs A, B, and C, respectively. The licensee indicated that the following Level 1 (i.e., the plant must be placed in a suitable hold condition until resolution is obtained) acceptance criterion applies to the condensate pump trip test:

- The trip of one condensate pump shall not cause the trip of all three RFPs.

The licensee indicated that the following Level 2 (i.e., operating and testing plans may continue) acceptance criteria apply to the condensate pump trip test:

- The trip of one condensate pump shall not cause the trip of more than one RFP.
- A recirculation runback shall occur upon the trip of a condensate pump.
- For the Phase 1 test only, the margin to tripping an RFP shall not be less than 10 psi.

The licensee also indicated that since the bounding analysis of a total LOFW flow is not a limiting transient from a thermal margin perspective, Phase 2 testing at the full CPPU power level is not warranted provided that the Phase 1 test results at 3733 MWt are satisfactory.

Based on a review of the information provided, the NRC staff finds that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the CFS to provide reactor FW for CPPU operation. The NRC staff agrees that the modifications being made to the CFS are appropriate and necessary to maintain the capability and reliability of the CFS. The NRC staff also agrees that because the CPPU analytical results indicate that the trip of a condensate pump is significantly more limiting than the trip of an RFP, condensate pump trip testing is adequate to confirm acceptable performance, and separate RFP trip testing is not necessary. To demonstrate that a single condensate pump trip will not result in a loss of all FW while operating at the full CPPU power level of 3952 MWt, PPL will perform transient testing on SSES Units 1 and 2 during each unit's Phase 1 power ascension test program and confirm that the plant response to the transient is as expected in accordance with the acceptance criteria established. The NRC staff has determined that the following license conditions should be imposed:

A. PPL will demonstrate through performance of transient testing on each SSES unit that the loss of one condensate pump will not result in a complete loss of reactor FW. The test shall be performed on each unit during the unit's CPPU power ascension test program within 336 hours of achieving and prior to exceeding a nominal power level of 3733 MWt with FW and condensate flow rates stabilized. PPL shall confirm that the plant response to the transient is as expected in accordance with the established acceptance criteria. If a loss of all reactor FW occurs as a result of the test, the licensee shall address the test failure in accordance with corrective action program requirements and the provisions of the power ascension test program before continuing the operation of the SSES unit above 3489 MWt.

B. Unless the NRC issues a letter notifying the licensee that the tests specified by License Condition A. adequately demonstrate that a single condensate pump trip will not result in a loss of all FW while operating at the full CPPU power level of 3952 MWt, PPL shall perform the transient test on either SSES unit (whichever unit is first to achieve the following operating conditions) specified by License Condition A. during the power ascension test program while operating at 3872 to 3952 MWt (98 percent to 100 percent of the full CPPU power level) with FW and condensate flow rates stabilized. The test shall be performed within 90 days of operating at greater than 3733 MWt and within 336 hours of achieving a nominal power level of 3872 MWt with FW and condensate flow rates stabilized. PPL will demonstrate through performance of transient testing on either SSES Unit 1 or Unit 2 (whichever unit is first to achieve the specified conditions) that the loss of one condensate pump will not result in a complete loss of reactor FW. PPL shall confirm that the plant response to the transient is as expected in accordance with the established acceptance criteria. If a loss of all FW occurs as a result of the test, the licensee shall address the test failure in accordance with corrective action program requirements and the provisions of the power ascension test program before continuing the operation of either SSES unit above 3733 MWt.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed CPPU on the CFS and finds that the CFS will remain capable of satisfying the FW demands for CPPU operation. However, because of the extent of CFS modifications required to implement the proposed power uprate, the staff has determined that condensate pump trip testing is necessary at the intermediate (Phase 1) power level of 3733 MWt for both units and must adequately demonstrate that a single condensate pump trip will not result in a loss of all FW while the unit is operating at the full CPPU power level of 3952 MWt. Consequently, the staff will impose appropriate license conditions to require that the necessary transient testing is completed as a prerequisite to prolonged operation at both the Phase 1 and full CPPU power levels to assure that CFS transient performance is consistent with the analytical results. Given these considerations, the NRC staff finds that adequate assurance will be established, before the commencement of prolonged Phase 1 and full CPPU power operation, that the CFS will remain reliable and will not increase the likelihood of LOFW events. Therefore, the CFS will continue to satisfy licensing-basis considerations, and the proposed CPPU is considered acceptable with respect to the CFS.

The licensee has evaluated the impact of the proposed CPPU on BOP systems and components and demonstrated that SSES Units 1 and 2 are capable of providing safe and reliable operation at an uprated NSSS power level of 3952 MWt upon completion of supporting plant modifications. Based on the considerations discussed in this evaluation and in particular, on the recognition that the licensee will demonstrate acceptable performance of the CFS before commencing prolonged operation at the Phase 1 and full CPPU power levels as discussed in Section 2.5.4.4 of this evaluation and as specified by license conditions that the NRC will impose, the staff finds that the licensee has adequately considered and addressed the effects of the proposed power uprate on the areas that are included within the scope of this evaluation. The staff concludes that the power uprate will not (1) involve a significant increase in the probability or consequences of an accident previously evaluated, (2) create the possibility of a new or different kind of accident from any accident previously evaluated, and (3) involve a significant reduction in a margin of safety. Therefore, the NRC staff considers the proposed CPPU to be acceptable with respect to BOP considerations.

2.5.5 Waste Management Systems

2.5.5.1 Gaseous Waste Management Systems

Regulatory Evaluation

The gaseous waste management system (GWMS) involves the control of radioactive gases that are typically collected in the offgas system and the waste gas storage and decay tanks. In addition, it involves the management of the condenser air removal system, the gland seal exhaust, and building ventilation system exhausts. (Section 2.7.2 presents the evaluation of the SGTS, which is not included within the scope of this section.) The NRC staff's review of the GWMS focuses on the effects that the proposed CPPU 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 criteria that are most applicable to the staff's review of the GWMS for proposed power uprates are based on (1) 10 CFR 20.1302, "Compliance with Dose Limits for Individual Members of the Public," insofar as it places specific limitations on the annual average concentrations of radioactive materials released at the boundary of the unrestricted area, (2) Sections II.B, II.C, and II.D of Appendix I, "Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion 'As Low as Is Reasonably Achievable' for Radioactive Material in Light-Water-Cooled Nuclear Power Reactor Effluents," to 10 CFR Part 50, (3) 10 CFR 50.67, insofar as offsite dose limits must not be exceeded, (4) GDC 3,"Fire Protection," insofar as it specifies that SSCs important to safety should be protected from the effects of explosions, and (5) other applicable licensing-basis considerations. The NRC staff reviewed the GWMS in accordance with the guidance in Section 2.1 of RS-001, Matrix 5, and judged its acceptability for power uprate operation based on conformance with existing licensing-basis considerations as discussed primarily in Section 11.3 of the SSES Unit 1 and 2 UFSAR, except where proposed changes are found to be acceptable based on the specified review criteria.

Technical Evaluation

As discussed in Section 8.2 of the licensee's PUSAR, the licensee evaluated the impact of the proposed power uprate on the capability of the GWMS to perform its functions and determined that sufficient capacity exists without modification to process the increase in gaseous waste that will result from CPPU operation. The radiological release rate is administratively controlled to remain within existing site release rate limits and is a function of fuel cladding performance, main condenser air inleakage, charcoal adsorber inlet dew point, and charcoal adsorber temperature. The licensee found that the proposed power uprate does not significantly affect any of these parameters and concluded that the CPPU primarily affects the flow rate of radiolytic hydrogen and oxygen to the offgas system. Consequently, the catalytic recombiner temperature and offgas condenser heat load are of interest. Because the SSES Unit 1 and 2 offgas system component design for heat load provides a substantial margin relative to the current radiolytic gas flow rate, the licensee concluded that the gaseous radwaste system will continue to satisfy the plant licensing basis.

Based on a review of the information submitted, the NRC staff finds that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the GWMS to perform its functions. Because the increase in offsite dose will remain well within limits, hydrogen flow rates and concentrations will remain within the design capability of the GWMS, and radiological release rates will continue to be administratively controlled during CPPU operation, the NRC staff agrees that the GWMS will continue to satisfy the plant licensing basis following implementation of the proposed power uprate.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed power uprate on the capability of the GWMS to perform its functions and finds that the GWMS will continue to control the release of radioactive materials and preclude the possibility of waste gas explosions in accordance with licensing-basis considerations. Therefore, the proposed power uprate is considered acceptable with respect to the GWMS.

2.5.5.2 Liquid Waste Management Systems

Regulatory Evaluation

The liquid waste management system (LWMS) consists of process equipment and instrumentation necessary to collect, process, monitor, store, recycle, and/or dispose of liquid radioactive waste. Major components include floor and equipment drains, transfer pumps, and various waste system tanks. The NRC staff's review of the LWMS for proposed power uprates focuses on the effects that the proposed power uprate may have on previous analyses and considerations used in estimating the increase in volume of the liquid radioactive waste. The criteria that are most applicable to the staff's review of LWMS for proposed power uprates are based on (1) 10 CFR 20.1302, insofar as it provides for demonstrating that annual average concentrations of radioactive materials released at the boundary of the unrestricted area do not exceed specified limits, (2) Sections II.A and II.D of Appendix I to10 CFR Part 50, which set numerical guides for dose design objectives and limiting conditions for operation to meet the "as low as reasonably achievable" (ALARA) criteria, and (3) other applicable licensing-basis considerations. The staff reviewed the LWMS in accordance with the guidance in Section 2.1 of RS-001, Matrix 5, and judged its acceptability for CPPU operation based on conformance with existing licensing-basis considerations as discussed primarily in Section 11.2 of the SSES Unit 1 and 2 UFSAR, except where proposed changes are found to be acceptable based on the specified review criteria.

Technical Evaluation

As discussed in Section 8.1 of the SSES Unit 1 and 2 PUSAR, the licensee determined that the largest CPPU effect on the LWMS is the increase in liquid and wet solid waste that will result from more frequent backwashing of the condensate filters and spent resins from the condensate demineralizers. Consequently, the licensee determined that each unit required an additional condensate filter and demineralizer in order to accommodate the increased condensate and FW flow rates that are needed for CPPU operation. The licensee estimated that the resultant increase in liquid radiological waste will be about 1 percent, which is not an appreciable increase when compared to the LWMS capacity. Since the design and operation of the LWMS will not change and the volume of fluid flowing into the liquid radwaste system will not increase significantly as a result of CPPU operation, the licensee concluded that the capacity of the LWMS will continue to be adequate.

Based on a review of the information submitted, the NRC staff finds that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the LWMS to perform its functions. Because the increase in radioactive waste generated because of power uprate operation is expected to be minimal and well within the capacity of the liquid radioactive waste processing system, any increase in offsite dose projections as a consequence is expected to be inconsequential and remain well below established plant release limits.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed CPPU on the capability of the LWMS to perform its functions and finds that the LWMS will continue to control the release of liquid radioactive materials in accordance with licensing-basis considerations. Therefore, the proposed CPPU is considered acceptable with respect to the LWMS.

2.5.5.3 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 wet waste dewatering and liquid collection processes and focuses on the impact that the proposed power uprate will have on the release of radioactive materials to the environment via gaseous and liquid effluents. Because Sections 2.5.5.1 and 2.5.5.2 fully address these considerations, a separate evaluation of solid waste management systems in this section is not required.

2.5.6 Additional Considerations

2.5.6.1 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 of the emergency diesel fuel oil storage and transfer system for proposed power uprates focuses on the effects that the proposed power uprate may have on the fuel oil storage requirements for the EDGs. The licensee indicated that the fuel oil consumption rate is based on the continuous full-load electrical rating of the EDG, and not on DBA time-dependent loads. Because the proposed power uprate does not have an impact on the electrical rating of the EDG, the fuel oil consumption rate of the EDGs is not affected. Consequently, the existing fuel oil storage requirements are also unaffected. Therefore, an evaluation of the EDG fuel oil storage requirements for the proposed power uprate is not required.

2.5.6.2 Light Load Handling System (Related to Refueling)

The light load handling system includes components and equipment used for handling new fuel at the receiving station and for loading spent fuel into shipping casks. Because the licensee is not introducing any new fuel designs in conjunction with the proposed CPPU, the proposed power uprate does not affect this area of review, and an evaluation of this system is not required.

2.5.6.3 Power Ascension and Testing Plan

The NRC's BOP Branch reviewed the licensee's power ascension and testing plan as it relates to two areas that are within the scope of the BOP evaluation. One area deals with the capability of the turbine bypass control system to discharge steam to the main condenser as assumed in the turbine generator load reject and turbine trip transient analyses. Because the licensee is not proposing to credit additional steam bypass capacity beyond that previously assumed, transient testing for the purpose of demonstrating the capacity of the turbine bypass control system is not required.

The other area of the staff's review focuses on transient testing that may be needed as a consequence of BOP modifications necessary to implement the proposed power uprate. In this regard and as discussed in Section 2.5.4.4, the NRC staff concluded that transient testing of the CFS is required to confirm acceptable performance during CPPU operation and, in particular, to ensure that the loss of a single condensate pump will not result in a complete loss of reactor FW. Therefore, the NRC will impose a license condition that requires CFS transient testing to be completed before prolonged operation at the Phase 1 CPPU power levels for SSES Units 1 and 2.

Section 2.12 of this SE presents the NRC staff's remaining technical evaluation for the licensee's power ascension and testing plan.

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 NRC staff's review of the primary containment functional design covered (1) the temperature and pressure conditions in the drywell and wetwell that would result from a spectrum of postulated LOCAs, (2) the differential pressure across the operating deck for a spectrum of LOCAs (Mark II containments only), (3) suppression pool dynamic effects during a LOCA or following the actuation of one or more RCS SRVs, (4) the consequences of a LOCA occurring within the containment (wetwell), (5) the capability of the containment to withstand the effects of steam bypassing the suppression pool, (6) the suppression pool temperature limit during RCS SRV operation, and (7) the analytical models used for containment analysis. The NRC's acceptance criteria for the primary containment functional design 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, (2) GDC 16, "Containment Design," insofar as it requires that reactor containment be provided to establish an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment, (3) GDC 50, "Containment Design Basis," insofar as it requires that the containment and its associated heat removal systems be designed so that the containment structure can accommodate, without exceeding the design leakage rate and with sufficient margin, the calculated temperature and pressure conditions resulting from any LOCA, (4) GDC 13, "Instrumentation and Control," insofar as it requires that instrumentation be provided to monitor variables and systems over their anticipated ranges for normal operation and for accident conditions, as appropriate, to assure adequate safety, and (5) GDC 64, "Monitoring Radioactivity Releases," insofar as it requires that means be provided to monitor the reactor containment atmosphere for radioactivity that may be released from normal operations and from postulated accidents. SRP Section 6.2.1.1.C contains specific review criteria.

Technical Evaluation

The primary containments for both SSES Unit 1 and Unit 2, as described in Section 3.8 of the SSES Unit 1 and 2 FSAR (Revision 58), form an enclosure for the RV, the reactor coolant recirculation loops, and other branch connections of the RCS. The major elements of the primary containment are the drywell, the pressure suppression chamber that stores a large volume of water, the drywell floor that separates the drywell and the suppression chamber, the connecting vent pipe system between the drywell and the suppression chamber, isolation valves, the vacuum relief system, and the containment cooling systems and other service equipment.

The primary containment is in the form of a truncated cone over a cylinder section, with the drywell in the upper conical section and the suppression chamber in the lower cylindrical section. The primary containment is made of reinforced concrete lined with welded steel plate. A steel domed head is provided for closure at the top of the drywell.

The proposal to operate at EPU conditions requires that safety analyses for those DBAs whose results depend on power level be recalculated at the higher power level. The containment design basis is primarily established based on the LOCA and the actuation of the RV SRVs and their discharge into the suppression pool.

The SSES Unit 1 and 2 FSAR reports the results of short-term and long-term containment analyses. The short-term analysis is directed primarily at determining the drywell pressure response during the initial blowdown of the RV inventory to the containment following a large break of a recirculation line inside the drywell. The long-term analysis is directed primarily at the suppression pool temperature response, considering the decay heat addition to the suppression pool. The effect of power on the events yielding the limiting containment pressure and temperature responses is described below.

The reevaluation of the long-term containment LOCA response reflects two changes to the SSES Unit 1 and 2 licensing basis. These changes are (1) crediting the presence of passive heat sinks and (2) the use of the ANSI/ANS 5.1-1979 decay heat model, which has a 2-sigma (σ) uncertainty instead of the ANS 5 model which has a 20-percent/10-percent uncertainty. Both of these changes are consistent with GE containment analyses accepted by the NRC for other BWR licensing actions. Both changes are acceptable for SSES Units 1 and 2 as discussed below.

Short-Term LOCA Analysis

The short-term analysis covers the blowdown period during which the maximum drywell pressure, maximum wetwell pressure, and maximum differential pressure between the drywell and the wetwell occur. The short-term LOCA analysis is performed for the limiting DBA LOCA, which assumes a double-ended guillotine break of a recirculation suction line, to show that the peak drywell pressure and temperature remain below the drywell design pressure of 53 psig and the drywell design temperature of 340 °F. The short-term analysis covers the blowdown period during which the maximum drywell pressure and maximum differential pressure between the drywell and suppression chamber occur. These analyses were performed at 2 percent above the EPU-rated thermal power (RTP), using analytic methods approved for EPUs. The RV steam dome pressure remains constant at its pre-EPU value. The EPU is therefore a CPPU. The licensee used the LAMB computer code (Reference 46) for the short-term mass and energy release and the M3CPT computer code (Reference 59) for the containment response. The power uprate methods approved by the NRC permit the use of either the M3CPT computer code or the LAMB computer code to calculate the mass and energy release from the postulated pipe break into the drywell (Reference 10).

The short-term containment analyses make several conservative assumptions. The reactor is assumed to be operating at 2 percent above the RTP to include instrument uncertainty effects, consistent with RG 1.49, “Power Levels of Nuclear Power Plants.” The suppression pool level and mass are at values corresponding to the maximum TS limit. The recirculation suction line is assumed to instantaneously undergo a double-guillotine break. The vessel depressurization flow rates are calculated using the Moody critical flow model (Reference 60) which maximizes the mass flow into the drywell. The MSIV closure time is minimized so as to maintain RV pressure which in turn maximizes the break flow into the drywell. The fluid flowing through the drywell-to-wetwell vents is assumed to be a homogenous mixture of the fluid in the drywell. Thus, the flow contains liquid droplets. The presence of these liquid droplets increases the pressure drop of the flow through the vents and therefore increases the drywell pressure. The FSAR analyses assume that there is no heat loss from the gases inside the primary containment. In reality, condensation of steam on the drywell surfaces would be expected. Neglecting this heat transfer is conservative for the short-term analyses.

The licensee has revised the assumed behavior of the FW flow into the vessel following the recirculation line break. The current licensing basis assumes that FW flow into the vessel continues at a flow rate which decreases with time (see FSAR Figure 6.2-9a). The CPPU analysis assumes reactor FW flow into the vessel remains at full rated flow for 10 seconds. The licensee has demonstrated that this assumption is more conservative than the current licensing basis (Reference 61) and it is, therefore, acceptable.

The licensee also made changes that reduce conservatism. The method of inputting break flow data into the M3CPT code has been revised. The licensee stated that the mass flow rate is still conservative and that a certain amount of overconservatism has been removed. Since the break flow rate remains conservative, the NRC staff finds this change acceptable.

Table 4-1 of the PUSAR (Reference 1) presents the results of these analyses at EPU and the acceptance criteria. The short-term portion of this table is reproduced below.

SSES Unit 1 and 2 Short-Term LOCA
Containment Performance Results

Parameter	Current Licensed Thermal Power from FSAR	Using CPPU Analysis Method with CLTP Assumptions	CPPU	Design Limit
Peak Drywell Pressure (psig)	44.6	47.9	48.6	53
Peak Drywell Air Space Temperature (°F)	320*	337(1)	337(1)	340
Peak Drywell-to-Wetwell (Down) Differential Pressure (psid)	27.0	25.9	25.6	28

* These peak drywell temperatures are for a large, double-ended guillotine break of a main steamline.

The table allows separation of the effects on important containment parameters that result from the power uprate and those that result from the change in analysis assumptions. The licensee's June 4, 2007, response to NRC RAI 3, describes the reasons for the differences between the parameters listed in this table. The differences in the short-term analyses shown in this table are primarily the result of different assumptions in the initial drywell and suppression chamber pressures.

The licensee stated that the decrease in peak differential pressure is primarily the result of a GE proprietary change in the method for calculating the wetwell pressures associated with the pool swell phenomenon. The NRC staff finds this change to be acceptable.

P_a is the pressure at which containment leakage rate testing is performed. It is defined in Appendix J to 10 CFR Part 50, as the calculated peak containment internal pressure related to the design-basis LOCA. The licensee proposed to revise P_a in SSES Unit 1 and 2 TS 5.5.1.2, Primary Containment Leakage Rate Testing Program, to 48.6 psig. The NRC staff finds this acceptable since P_a, the calculated peak containment internal pressure related to the design-basis LOCA for the EPU, is determined with acceptable methods and assumptions.

The licensee also proposed to change TS 3.6.1.3.12, which requires leakage rate testing of the MSIVs, to revise the test pressure from 22.5 psig (which is half of the current value of P_a) to 24.6 psig (which is half of the proposed value of P_a). Since the value of P_a is acceptable, this change is acceptable.

Based on the use of acceptable calculation methods and conservative assumptions and results less than the design containment pressure and temperature, the NRC staff finds the SSES Unit 1 and 2 short-term containment response at EPU to be acceptable.

Long-Term LOCA Analysis

The long-term LOCA analysis was performed for the DBA LOCA at 2 percent above the EPU RTP. The SHEX computer code (Reference 62) is used for the analysis of the peak suppression pool temperature, long-term peak wetwell pressure, and peak wetwell air temperature. The NRC has accepted this computer code for previous power uprate applications.

After 600 seconds into the accident, it is assumed that the operator actuates the RHR heat exchangers using the RHRSWS as the heat sink. The initial suppression pool level is at its minimum value. The calculation includes the effects of decay heat, stored energy, and energy from the metal water reaction.

The licensee previously used the ANS 5-1971 decay heat model with a +20 percent/10 percent margin for uncertainty (Reference 61). For the EPU, the licensee proposes to use the ANSI/ANS 5.1-1979 decay heat model with a 2-sigma uncertainty added (Reference 62). The licensee incorporated the guidance of GE Service Information Letter (SIL) 636, Revision 1 (Reference 63), which recommends accounting for additional actinides and activation products, which further increases the predicted decay heat. Because the NRC staff has accepted the ANSI/ANS 5.1-1979 decay heat model with a two-sigma uncertainty in previous EPU reviews, as well as other safety analyses, it is acceptable for SSES Units 1 and 2.

The licensee currently credits the suppression pool as the only passive heat sink available in the containment system. For the EPU, the licensee proposes to credit heat transfer from the containment atmosphere to passive heat sinks in the drywell, suppression chamber air space, and suppression pool. The NRC staff has reviewed the licensee's approach and finds it conservative and acceptable.

The RHR system heat exchanger removes heat from the suppression pool. When the energy removal rate of the RHR system exceeds the energy addition rate from the decay heat and pump heat, the containment pressure and temperature reach a second peak value and decrease gradually.

An important parameter characterizing the performance of the suppression pool is the K value of the RHR heat exchanger. For SSES Units 1 and 2, K equals 317.5 British thermal units per second-degrees Fahrenheit (Btu/s-°F). This is the value assumed in the current licensing-basis analysis for containment response. The RHR heat exchangers are periodically tested according to the recommendations of NRC GL 89-13 (Reference 65). This testing ensures that the heat exchangers meet or exceed this K value.

The long-term LOCA analysis demonstrates that the peak suppression pool temperature and wetwell pressure remain below their respective design limits. Table 4 -1 of the PUSAR presents the results of these analyses and the acceptance criteria. The relevant portions of this table are reproduced below.

Susquehanna Long-Term Containment Performance Results
(At Extended Power Uprate)

Parameter	CLTP from FSAR	Using CPPU analysis method with CLTP assumptions	CPPU	Design Limit
Peak Bulk Pool Temperature (°F)	203	192	211.2	220
Peak Wetwell Pressure (psig)	35.3	36.7	36.5	53

The wetwell pressure peaks early in the event and then peaks again around the time at which the wetwell temperature peaks. This table presents the value of the second (lower) peak pressure.

The EPU peak suppression pool temperature of 211.2 °F is less than the suppression pool design temperature of 220 °F. Since the licensee used acceptable calculation methods and conservative assumptions and the calculated values are below the design limits, the long-term containment calculations for extended power conditions are acceptable.

Hydrodynamic Loads

Part of the containment design basis is the acceptable response of the containment to hydrodynamic loads associated with the discharge of reactor steam and drywell nitrogen into the suppression pool following a LOCA or the discharge of reactor steam following actuation of the SRVs. The licensee used analytical and empirical methods developed by the ad hoc Mark II

Owners' Group and approved by the NRC staff in NUREG-0808 (Reference 66) to address these issues for SSES Units 1 and 2.

The licensee must ensure, as part of the power uprate evaluation, that these analyses remain bounding for operation at CPPU conditions. This is done for the LOCA by means of short-term calculations of the pressure and temperature response to a double-ended break of an RCS recirculation line. The key parameters are the drywell and wetwell pressure, vent flow rates, and the suppression pool temperature.

The licensee considered LOCA-induced loads such as the submerged boundary loads during vent clearing, pool swell loads, and LOCA steam condensation pool boundary loads (CO and chugging). Vent clearing refers to the ejection of water in the downcomers caused by drywell pressurization as a result of the LOCA. Vent clearing produces pressure loads on the containment basemat and the submerged suppression chamber walls. The NRC acceptance criteria stipulate an overpressure criterion on the basemat and walls below the vent exit of 24 psi. The licensee stated that an evaluation of the specified load concludes that the 24 psi overpressure is not exceeded.

The pool swell loads are a function of the initial drywell pressurization rate during a LOCA. The licensee stated that the results of the CPPU pool swell analysis are bounded by the current analysis. The licensee discussed the reasons for this in response to an NRC RAI (Reference 61). The NRC staff finds the licensee's explanation acceptable, since it is based on the use of the NRC-approved computer code (currently designated as PICSM) and the assumptions are consistent with the NRC recommendations of NUREG-0808 and NUREG-0487 (Reference 67). These reports reviewed the Mark II containment hydrodynamic loads testing and analyses and provided acceptance criteria acceptable to the NRC staff for plant-specific analyses.

Condensation loads increase with higher suppression pool temperature and/or a higher vent mass flow rate. The licensee compared the break flow rate (and hence the vent flow) for CPPU conditions with the vent flow calculated for the GKM-II-M test. (GKM II was a full-scale, single-vent test facility used by the licensee to obtain CO and chugging data.) The CO loads remain bounding. Therefore, the CO loads for the CPPU are acceptable.

The licensee's evaluation of containment hydrodynamic loads as a result of a LOCA is in accordance with the EPU topical report (Reference 10) and shows acceptable results. These results are therefore conservative and acceptable for the EPU.

Safety/Relief Valve Loads

The dynamic loads on the suppression pool due to the discharge of steam from SRVs are part of the containment design basis. The SRV loads evaluated for the CPPU are loads on the quenchers, quencher supports, and SRV discharge lines; loads on the submerged boundary of the suppression pool; and loads on submerged structures in the suppression pool.

The parameters that affect the SRV loads, the RV pressure, the SRV opening and closing setpoints, the submergence of the quenchers, the line air volume, and the automatic depressurization system (ADS) setpoints do not change for the CPPU. Therefore, the CPPU does not affect the SRV loads.

Local Pool Temperature with MSRV Discharge

NUREG-0783 (Reference 68) specifies a local pool temperature limit for SRV discharge because of concerns resulting from unstable condensation observed at high pool temperatures in BWRs without quenchers. The licensee indicated that an evaluation of the SSES Unit 1 and 2 peak local suppression pool temperature for EPU shows that the temperature meets the NUREG-0783 criteria. The SRV flow capacities and the configuration of the SSES Unit 1 and 2 T-quenchers remain unchanged for EPU, and the predicted local pool temperatures remain below the NUREG-0783 limit. Therefore, the SSES Unit 1 and 2 peak local suppression pool temperature is acceptable for the EPU conditions.

The licensee has not proposed any changes to instrumentation and controls provided to monitor and maintain variables within prescribed operating ranges. The licensee also has not proposed any changes to instrumentation used to monitor the reactor containment atmosphere for radioactivity that may be released from normal operations and from postulated accidents.

Conclusion

The NRC staff has reviewed the licensee's assessment of the containment temperature and pressure transient and concludes that the licensee has adequately accounted for the increase of mass and energy resulting 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 containment systems and instrumentation will continue to be adequate for monitoring containment parameters and release of radioactivity during normal and accident conditions and the containment and associated systems will continue to meet the requirements of GDC 4, 13, 16, 50, and 64 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to primary containment functional design.

2.6.2 Subcompartment Analyses

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 of subcompartment analyses covered the determination of the design differential pressure values for containment subcompartments. The staff's review focused on the effects of the increase in mass and energy release into the containment caused by 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 resulting from the calculated pressure differential conditions across the walls of the subcompartments. SRP Section 6.2.1.2 contains specific review criteria.

Technical Evaluation

The licensee stated that the mass and energy releases that affect annulus pressurization loads on the biological shield wall caused by a postulated recirculation suction line break, FW line break, or MSLB were evaluated at CPPU conditions (Reference 1). The methods used for the evaluation are consistent with those used in the existing SSES Unit 1 and 2 analysis of record, including the evaluation performed for ARTS/MELLLA. For the MSLB, [[ ]], the mass and energy released following an MSLB do not change. For the RSLB, the current licensing analysis has a higher mass release [[ ]] during operation at minimum core flow (MELLLA domain). [[

]] Thus, the mass and energy released would be less for an RSLB at CPPU conditions.

For the FWLB, CPPU conditions result in a higher mass flow rate and break fluid enthalpy [[ ]], which causes a higher mass and energy release than that reflected in the current SSES Unit 1 and 2 licensing basis.

The SSES Unit 1 and 2 FSAR also contains an analysis for the drywell head region subcompartment. The licensee did not perform this analysis at CPPU conditions. The GE proprietary basis for this is described in response to NRC staff RAI 9(d) (Reference 61). The NRC staff has reviewed the licensee's basis for not re-performing the analysis and finds it acceptable.

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 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 as the result of pressure difference across the walls following implementation of the proposed EPU. Based on these findings, the staff concludes that the plant will continue to meet GDC 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

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) Appendix K, "ECCS Evaluation Models," to 10 CFR Part 50, insofar as it identifies sources of energy during a LOCA. SRP Section 6.2.1.3 contains specific review criteria.

Technical Evaluation

Section 2.6.1, Primary Containment Functional Design, discusses the mass and energy release following an HELB in containment.

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 Appendix K to 10 CFR Part 50. Based on this, the 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 a postulated LOCA.

2.6.4 Combustible Gas Control in Containment

Regulatory Evaluation

Following a LOCA, hydrogen and oxygen may accumulate inside the containment as the result of 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 the mitigation of any increases in hydrogen release.

The NRC's acceptance criteria for combustible gas control in containment are based on (1) 10 CFR 50.44, "Combustible Gas Control for Nuclear Power Reactors," insofar as it requires that plants be provided with the capability of controlling combustible gas concentrations in the containment atmosphere, (2) GDC 5, "Sharing of Structures, Systems, and Components," 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, "Containment Atmosphere Cleanup," 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. SRP Section 6.2.5 contains specific review criteria.

Technical Evaluation

The post-LOCA production of hydrogen and oxygen by radiolysis increases proportionally with the power level. The hydrogen recombiner system, which is designed to maintain the hydrogen concentration below the combustible limit set by RG 1.7, "Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident," controls the hydrogen concentration in containment. Each unit has four hydrogen recombiners, two in the drywell and two in the suppression chamber. One recombiner in the drywell and one in the wetwell will provide 100 percent of the required capacity. Because of the increased production of hydrogen and oxygen resulting from the EPU, the system must be started soon after the beginning of the accident. This does not significantly affect operator response since the system is not required for many hours after accident initiation.

The licensee analyzed the post-LOCA control of combustible gases at EPU conditions. Section 4.7 and Figures 4-1 through 4-3 of the PUSAR give the results of the combustible gas analyses. For SSES Units 1 and 2, the required start time of the drywell hydrogen recombiners decreases from 24.5 hours to19.5 hours. The startup time for the suppression chamber recombiners decreases from 38 hours to 11.1 hours. The licensee stated that the existing procedures specify starting the hydrogen recombiners before the hydrogen concentration reaches 2 percent, which occurs approximately 2 to 3 hours after event initiation, well before the 11.1- and 19.5-hour start times required to maintain the hydrogen concentration below the flammability limit.

Although the startup time for the hydrogen recombiners has significantly decreased, the time available is still sufficient for the operator to take the required actions and is still long compared to the guidance in the SSES Unit 1 and 2 procedures.

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 and 10 CFR 50.46 for systems being provided to control the concentration of hydrogen or oxygen that may be released into the reactor containment following postulated accidents to ensure containment integrity is maintained at extended power. 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 wetwell. The NRC staff's review in this area focused on (1) the effects of the proposed EPU on the analyses of the NPSH available 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, "Containment Heat Removal," insofar as it requires that a containment heat removal system be provided and that its function shall be to rapidly reduce the containment pressure and temperature following a LOCA and maintain them at acceptably low levels. SRP Section 6.2.2, as supplemented by Draft Guide 1107, "Water Sources for Long-Term Recirculation Cooling Following a Loss-of-Coolant Accident," contains specific review criteria.

Technical Evaluation

The CPPU increases the reactor decay heat, which increases the heat input to the suppression pool. This increased heat input increases the peak suppression pool water temperature, which may affect operation of the RHR and core spray pumps. The following table gives the peak suppression pool temperatures for both the design-basis and nondesign-basis events:

Event	Peak Temperature (°F)
LOCA	211.2
Alternate Shutdown Cooling Event	211.6
SBO	156.6
ATWS	206
Appendix R Fire Including SORV	191

The available NPSH for the RHR and core spray pumps was analyzed at the maximum calculated pump flow, which exceeds the design-basis pump flows, and a peak suppression pool temperature of 220 °F, which is the design suppression chamber temperature. The analysis assumes that the containment pressure will equal the vapor pressure of the suppression pool water to ensure that credit is not taken for containment accident pressure during the transient. This is consistent with the guidance of SRP Section 6.2.2. The required NPSH has not changed from the current values.

The SSES Unit 1 and 2 strainer design requirements are pressure drop, flow rate, and debris loading based on the worst-case short-term and long-term ECCS operation following a postulated LOCA. All debris sources in the containment are assumed available for transport to the suction strainers. This is more conservative than the guidance developed by the BWROG and approved by the NRC (Reference 69).

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, with respect to 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

Regulatory Evaluation

The secondary containment structure and supporting systems of dual containment plants are provided to collect and process radioactive material that may leak from the primary containment following an accident. The supporting systems maintain a negative pressure within the secondary containment and process this leakage. The NRC staff's review covered (1) analyses of the pressure and temperature response of the secondary containment following accidents within the primary and secondary containments, (2) analyses of the effects of openings in the secondary containment on the capability of the depressurization and filtration system to establish a negative pressure in a prescribed time, (3) analyses of any primary containment leakage paths that bypass the secondary containment, (4) analyses of the pressure response of the secondary containment resulting from inadvertent depressurization of the primary containment when there is vacuum relief from the secondary containment, and (5) the acceptability of the mass and energy release data used in the analysis. The review primarily focused on the effects that the proposed EPU may have on the pressure and temperature response and drawdown time of the secondary containment and the impact this may have on offsite dose. The NRC's acceptance criteria for secondary containment functional design are based on (1) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of environmental conditions associated with normal operation, maintenance, testing, and postulated accidents and be protected from dynamic effects (e.g., the effects of missiles, pipe whipping, and discharging fluids) that may result from equipment failures, and (2) GDC 16, insofar as it requires that reactor containment and associated systems be provided to establish an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment. SRP Section 6.2.3 contains specific review criteria.

Technical Evaluation

An increase in RTP increases the heat load on the secondary containment and affects the drawdown time of the secondary containment. The drawdown time is the time period following the start of the accident during which loss of offsite power causes loss of secondary containment vacuum (relative to atmospheric pressure) which is assumed to result in releases from the primary containment directly to the environment without filtering.

The licensee stated that the secondary containment drawdown analysis was reviewed for CPPU impact. The CPPU results in a small increase in the operating heat load within the zones of the secondary containment which contributes to the heatup and pressurization within the reactor building after the loss of the normal HVAC systems. The licensee stated that this increase is enveloped by the design heat load values used in the analysis. Therefore, the CPPU does not require a change in the secondary drawdown time.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the secondary containment pressure and temperature transient and the ability of the secondary containment to provide an essentially leak-tight barrier against uncontrolled release of radioactivity to the environment. The staff concludes that the licensee has adequately accounted for the increase of mass and energy that would result from the proposed EPU and further concludes that the secondary containment and associated systems will continue to provide an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment following implementation of the proposed EPU. Based on this, the staff also concludes that the secondary containment and associated systems will continue to meet the requirements of GDC 4 and 16. Therefore, the NRC staff finds the proposed EPU acceptable with respect to secondary containment functional design.

2.6.7 Containment Isolation

Regulatory Evaluation

The NRC's acceptance criteria for containment isolation are based on GDC 50, insofar as the containment structure, including penetrations, shall be designed to accommodate, without exceeding design leakage rate and with sufficient margin, the calculated pressure and temperature conditions resulting from any LOCA.

Technical Evaluation

The licensee's response to GL 96-06 (Reference 50) identified a total of 13 containment penetrations potentially susceptible to thermally induced overpressurization during DBAs. Of the 13, one was eliminated through procedural changes, and another was shown by analysis not to be susceptible to failure based on system and piping configuration. For the remaining 11 penetrations, the licensee showed that failure of the pressure boundary of the piping or valve body will not occur.

The licensee has determined that the higher temperatures of CPPU conditions will not affect the calculated leakage pressure through the valve bonnet gaskets and discs for each of these 11 penetrations. Therefore, there are no changes to resolution for thermally induced overpressurizations that were previously accepted by the NRC.

Conclusion

Based on the above, the NRC staff finds that the EPU does not adversely affect system designs for containment isolation capabilities, which continue to meet the requirements of GDC 50. Therefore, the staff finds the proposed EPU acceptable with respect to containment isolation.

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. Another 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, "Control Room," 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 0.05 sievert (Sv) (5 roentgen equivalent man (rem)) total effective dose equivalent (TEDE) as defined in 10 CFR 50.2, "Definitions," for the duration of the accident. SRP Section 6.4 and other guidance in Matrix 7 of RS-001 contain specific review criteria.

Technical Evaluation

The heat sources for the main control room atmosphere control system are from equipment, ambient outside air temperature, and the personnel in the control room. Heat loads from these sources do not change for the CPPU. The SSES Unit 1 and 2 control room habitability envelope (CRHE) includes all areas of the control structure between plan floor elevations 697'-0" and 783'-0," Stairwells 120 and 221, vestibule C-131 on elevation 676'-0", and the passenger elevator. The control room emergency outside air supply system (CREOASS) processes outside air needed to ventilate and pressurize the CRHE during accident conditions. The CREOASS unit is automatically started and the CRHE is isolated upon receipt of a DBA initiation signal or high radiation signal in the CREOASS intake duct. When the CRHE is isolated, a fixed flow rate of outside air is filtered through CREOASS filter banks, which include a heating coil, roughing filter, upstream HEPA filter, charcoal filter bed, and downstream HEPA filter.

The licensee's review concluded that the radiological effect of the CPPU on CRHE and CREOASS results from an increase in the core iodine activity released during the DBAs. The effect of the CPPU in combination with a 24-month fuel cycle and the AST methodology on the post-LOCA iodine loading of the CREOASS charcoal filter was evaluated. According to Table 1 of RG 1.183, "Alternative Radiological Source Terms for Evaluating Design-Basis Accidents at Nuclear Power Reactors," issued July 2000, a total of 30 percent of the core iodine is released to the drywell. All iodines (particulates, elemental, organic, and stable) in the drywell are conservatively assumed to be released to the environment without crediting radiological decay or removal by the SGTS charcoal filtration system, or holdup and plate-out of iodine on the MS piping/condenser surface. Dispersion of the released radioiodine is conservatively based on the limiting 0–2 hour X/Q value for the entire 30-day event. As a result of the CPPU, the iodine loading on the CREOASS filters remains a small fraction of the allowable limit of 2.5 mg of total iodine (radioactive plus stable) per gram of activated carbon, identified in RG 1.52, "Design, Inspection, and Testing Criteria for Air Filtration and Adsorption Units of Post-Accident Engineered-Safety-Feature Atmosphere Cleanup Systems in Light-Water-Cooled Nuclear Power Plants." Therefore, the CPPU does not affect CREOASS iodine filter efficiency.

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 staff concludes that the licensee has adequately accounted for the increase of toxic and radioactive gases that would result from the proposed EPU. The staff also concludes that the control room habitability system will continue to provide the required protection following implementation of the proposed EPU. Based on this, the staff concludes that the control room habitability system will continue to meet the requirements of GDC 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 Atmosphere Cleanup

Regulatory Evaluation

ESF atmosphere cleanup systems are designed for fission product removal in postaccident environments. These systems generally include primary systems (e.g., in-containment recirculation) and secondary systems (e.g., SGTSs and 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 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 0.05 Sv (5 rem) TEDE as defined in 10 CFR 50.2, 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 be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including AOOs, and postulated accidents. SRP Section 6.5.1 contains specific review criteria.

Technical Evaluation

The SGTS is one of the fission product control systems and structures that provides fission product control during DBA conditions. Other systems and structures that provide this function include primary containment, secondary containment, and the reactor building recirculation system. These systems and structures are determined to be acceptable for CPPU operation.

The reactor building recirculation system fan flow capacity, boundary parameters, system component parameters, or system start signals do not change as a result of CPPU conditions. Therefore, the CPPU does not affect the reactor building recirculation system.

Following a LOCA, the fission products released from the reactor are contained within the primary containment. Fission product leakage from the primary containment is into the secondary containment (reactor building) where it is processed via the SGTS before it is released to the environment. During LOCA conditions, the reactor building recirculation system mixes the inleakage from the primary containment with the secondary containment volume so that the concentration of fission products is diluted. SGTS filters the air through the SGTS charcoal and HEPA filters before exhausting the air to the outside atmosphere and maintains a negative pressure inside secondary containment with respect to the outside atmosphere. This minimizes the potential for uncontrolled release during SGTS operation.

The SSES Unit 1 and 2 SGTS design flow capacity is adequate to maintain the secondary containment at the required negative pressure to minimize the potential for exfiltration of air from the reactor building. The CPPU does not affect this capability because the specified primary and secondary leak rates are not adversely affected by CPPU operation, and the high-efficiency particulate air (HEPA) filters have sufficient design margin to accommodate additional fission product loading without restricting flow rate.

The charcoal adsorber removal efficiency for radioiodine is also unaffected by the CPPU. The total (radioactive plus stable) post-LOCA iodine loading on the charcoal adsorbers increases proportionally with the increase in core iodine inventory, which is proportional to core thermal power. Sufficient charcoal mass is present so that the post-LOCA iodine loading on the charcoal remains below the guidance provided by RG 1.52.

While decay heat from fission products accumulated within the system filters and charcoal adsorbers increases in proportion to the increase in thermal power, the cooling air flow required to maintain components below operating temperature limits is well below the cooling flow capability of the system.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ESF atmosphere cleanup systems. The 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 staff also finds 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 staff concludes that the ESF atmosphere cleanup systems will continue to meet the requirements of GDC 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 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 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 0.05 Sv (5 rem) TEDE as defined in 10 CFR 50.2, 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. SRP Section 9.4.1 contains specific review criteria.

Technical Evaluation

The heat sources for the control room area are from equipment, ambient outside air temperature, and the personnel in the control room. Heat loads from these sources do not change for the CPPU. The SSES Unit 1 and 2 CRHE includes all areas of the control structure between plan floor elevations 697'-0" and 783'-0", stairwells 120 and 221, vestibule C-131 on elevation 676'-0", and the passenger elevator. As the heat loads do not change for the CPPU, the existing control room area cooling system remains adequate to control the temperature. Previously in this SE, Section 2.7.1 considered the effects of radioactive gases.

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 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. Based on this, the 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 SFP 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 that contain radioactivity be designed with appropriate confinement and containment. SRP Section 9.4.2 contains specific review criteria.

Technical Evaluation

The HVAC systems consist mainly of heating, cooling, supply, exhaust, and recirculation units in the primary containment, control structure (including the control room), reactor building (including the SFP area and the ECCS pump rooms), turbine building, radwaste building, diesel generator buildings, essential safeguards service water (ESSW) pumphouse, and circulating water pumphouse. Also included are the associated chilled water systems which are the control structure chilled water, reactor building chilled water, radwaste building chilled water, and turbine building chilled water systems. CPPU results in slightly higher process temperatures and a small increase in the heat load because of higher electrical currents in some motors and cables.

The affected areas are the primary containment; steam tunnel in the reactor building; and the FW heater bay, condenser areas, condensate pump room, and the steam-driven FW pump areas in the turbine building. The HVAC systems that provide cooling to these areas and their associated chilled water systems are affected. Other areas of the reactor building and turbine building are unaffected by the CPPU because the process temperatures remain relatively constant. The control structure building, radwaste building, diesel generator buildings, ESSW pumphouse, and circulating water pumphouse are unaffected by the CPPU. Because the CPPU does not affect the temperature of the areas served by the control structure chilled water and radwaste building chilled water systems, these systems are not impacted by the CPPU.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the SFPAVS. The 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 SFP 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 these findings, the staff concludes that the SFPAVS will continue to meet the requirements of GDC 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 Area 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 the means to control the release of radioactive effluents. SRP Sections 9.4.3 and 9.4.4 contain specific review criteria.

Technical Evaluation

The HVAC systems consist mainly of heating, cooling, supply, exhaust, and recirculation units in the primary containment, control structure (including the control room), reactor building (including the SFP area and the ECCS pump rooms), turbine building, radwaste building, diesel generator buildings, ESSW pumphouse, and circulating water pumphouse. Also included are the associated chilled water systems which are the control structure chilled water, reactor building chilled water, radwaste building chilled water, and turbine building chilled water systems. The CPPU results in slightly higher process temperatures and a small increase in the heat load because of higher electrical currents in some motors and cables.

The affected areas are the primary containment; steam tunnel in the reactor building; and the FW heater bay, condenser areas, condensate pump room, and steam-driven FW pump areas in the turbine building. The HVAC systems that provide cooling to these areas and their associated chilled water systems are affected. Other areas of the reactor building and turbine building are unaffected by the CPPU because the process temperatures remain relatively constant. The control structure building, radwaste building, diesel generator buildings, ESSW pumphouse, and circulating water pumphouse are unaffected by the CPPU. Because the CPPU does not affect the temperature of the areas served by the control structure chilled water and radwaste building chilled water systems, these systems are not impacted by the CPPU.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ARAVS and TAVS. The 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 these findings, the 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 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 of the ESFVS focused on the effects of the proposed EPU on the functional performance of the safety-related portions of the system. The 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 that 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 the means to control the release of radioactive effluents. SRP Section 9.4.5 contains specific review criteria.

Technical Evaluation

The HVAC systems consist mainly of heating, cooling, supply, exhaust, and recirculation units in the primary containment, control structure (including the control room), reactor building (including the SFP area and the ECCS pump rooms), turbine building, radwaste building, diesel generator buildings, ESSW pumphouse, and circulating water pumphouse. Also included are the associated chilled water systems, which are the control structure chilled water, reactor building chilled water, radwaste building chilled water, and turbine building chilled water systems. The CPPU results in slightly higher process temperatures and a small increase in the heat load because of higher electrical currents in some motors and cables.

The affected areas are the primary containment; the steam tunnel in the reactor building; and the FW heater bay, condenser areas, condensate pump room, and the steam-driven FW pump areas in the turbine building. The HVAC systems that provide cooling to these areas and their associated chilled water systems are affected. Other areas of the reactor building and turbine building are unaffected by the CPPU because the process temperatures remain relatively constant. The control structure building, radwaste building, diesel generator buildings, ESSW pumphouse, and circulating water pumphouse are unaffected by the CPPU. Because the CPPU does not affect the temperature of the areas served by the control structure chilled water and radwaste building chilled water systems, these systems are not impacted by the CPPU.

The SGTS is one of the fission product control systems and structures that provides fission products control during DBA conditions. Other systems and structures that provide this function include primary containment, secondary containment, and the reactor building recirculation system. Section 2.7.2 presents the SGTS evaluation.

The reactor building recirculation system fan flow capacity, boundary parameters, system component parameters, or system start signals do not change as a result of CPPU conditions. Therefore, the CPPU does not affect the reactor building recirculation system.

Following a LOCA, the fission products released from the reactor are contained within the primary containment. Fission product leakage from the primary containment is into the secondary containment (reactor building) where it is processed via the SGTS before it is released to the environment. During LOCA conditions, the reactor building recirculation system mixes the inleakage from the primary containment with the secondary containment volume so that the concentration of fission products is diluted.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ESFVS. The 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 staff further concludes that the ESFVS will continue to assure a suitable environment for the ESF components following implementation of the proposed EPU. The 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 these findings, 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.

2.8 Reactor Systems

GE previously developed and implemented EPUs using NRC-approved LTRs NEDC-32424P-A (Reference 8), known as ELTR1, and NEDC-32523P-A (Reference 9), known as ELTR2. Based on its EPU experience, GE developed an approach to uprate reactor power that maintains the current plant maximum normal operating reactor dome pressure. This approach, referred to as the CPPU, is contained in NRC-approved LTR NEDC-33004P-A, Revision 4, also known as the CLTR (Reference 10).

Some topics in the CLTR are fuel dependent because the fuel type affects the resulting evaluation or the consequences of transients or accidents. Because SSES contains only AREVA ATRIUM-10 fuel, the licensee's PUSAR (Attachment 4 to Reference 1) provides a plant-specific evaluation for areas involving reactor systems and fuel issues, consistent with the NRC staff's conditions and limitations on the use of the CLTR. PPL Susquehanna or AREVA performed most of the fuel-dependent evaluations by using approved codes and methods. The NRC staff audited these methods. The anticipated transient without scram (ATWS) analysis is a fuel-dependent evaluation performed by GE.

For the evaluations that are not fuel dependent, this report considers the PPL Susquehanna application of the CLTR approach to SSES, including the performance of plant-specific engineering assessments and confirmation of the applicability of the CLTR generic assessments required to support a CPPU.

2.8.1 Fuel System Design

The fuel system consists of arrays of fuel rods, burnable poison rods, spacer grids and springs, end plates, channel boxes, and reactivity control rods. The NRC staff reviewed the fuel system to ensure that (1) the system is not damaged as a result of normal operation and 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 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.

Regulatory Evaluation

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) 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, "Combined Reactivity Control Systems Capability," insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, or reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure that the capability to cool the core is maintained, and (4) GDC 35, "Emergency Core Cooling," 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. SRP Section 4.2 contains specific review criteria, and Matrix 8 of RS-001 provides other guidance.

Technical Evaluation

Section 4.2 of the UFSAR for SSES Units 1 and 2 (Reference 11) describes the fuel system design at SSES Units 1 and 2. The fuel at both units is entirely AREVA ATRIUM-10 fuel. The NRC staff based its evaluation on Chapter 2 of the SSES PUSAR.

The ATRIUM-10 fuel design consists of a 10x10 array of fuel rods with a central water channel that also provides structural support for the assembly by attachment to the upper and lower tie plates. The licensee has been using ATRIUM-10 fuel at Unit 1 since Cycle 11 and at Unit 2 since Cycle 9. Mechanical analyses were performed using RODEX2, RODEX2A, RAMPEX, and COLAPX, and the licensee indicated that the fuel has been evaluated for uprate conditions (References 12–16).

The licensee stated that the average bundle power for CPPU conditions will be 5.17 MWt/bundle. For each cycle of operation, the fuel lattice and core design will be modified to meet the operating requirements for that cycle. These changes might include enrichment and burnable absorber distributions and reload batch size. The core loading is designed such that the power distributions throughout the cycle provide margin to the following operating limits:

- the minimum critical power ratio (MCPR)—ensures an acceptably low probability of fuel cladding failure resulting from the fuel experiencing boiling transition

- the linear heat generation rate (LHGR)—ensures that fuel thermal and mechanical design bases are met

- the maximum average planar linear heat generation rate (MAPLHGR)—ensures that PCT and metal-water reaction (MWR) criteria for the limiting LOCA are met

The licensee performed evaluations to assess operation at CPPU conditions with ATRIUM-10 fuel and assumed an equilibrium core of ATRIUM-10 fuel. The licensee stated that fuel and core design limits are met by the planned enrichment, burnable absorber, and control rod positions in the reload core design. The methods used to perform the SSES ATRIUM-10 fuel and core design analyses are NRC approved and show that the equilibrium cycle core of ATRIUM-10 meets the specified CPPU operating requirements while remaining within the operating limits. The NRC staff performed an audit at the AREVA facility in Richland, Washington, to verify that the methods for determining the operating limits were applied in a manner consistent with the staff's approval of each method referenced in TS 5.6.(b), "Core Operating Limits Report."

During the audit (Reference 7), AREVA personnel presented the NRC staff with an extensive description of the vendor's fuel design and safety analysis methods, which the staff reviewed. Based on its review of the audit presentation materials, the staff concluded that the safety analysis methods, particularly those required to generate the core operating limits report (COLR), were NRC-approved methods and were applied in a manner consistent with their approval.

The licensee stated that the ATRIUM-10 reload core designs for operation at CPPU conditions will consider the operating limits discussed above (MCPR, LHGR, and MAPLHGR) to ensure that acceptable design margins exist between the licensing limits and their corresponding operating values. The licensee stated that fuel for the uprated, equilibrium core will remain within the NRC-approved exposure limits in Reference 14.

The percent power level above which fuel thermal margin monitoring is required will change with the CPPU. The original plant operating licenses set this monitoring threshold at a typical value of 25 percent of RTP. For SSES, the fuel thermal monitoring threshold is established at 23 percent of CPPU RTP. A change in the fuel thermal monitoring threshold also requires a corresponding change to the TS reactor core safety limit for reduced pressure or low core flow.

By letter dated May 14, 2007, the NRC staff asked the licensee to explain the technical basis for establishing the thermal limits monitoring threshold at 23 percent of the uprated power level. In Reference 5, the licensee responded that the threshold is based on a re-scaling of the thermal limits monitoring threshold to require thermal limits monitoring at an average absolute bundle power level that is consistent with industry practice. The staff finds that this re-scaling will continue to ensure that the thermal limits will be monitored at times when, during normal operation and AOOs, the fuel thermal limits could be challenged. On this basis, the NRC staff finds the thermal limits monitoring threshold re-scaling acceptable.

<u>Thermal Limits Assessment</u>

The NRC's acceptance criteria require that the reactor core and the associated control and instrumentation systems be designed with appropriate margin to ensure that the SAFDLs are not exceeded during normal operation, including AOOs. Operating limits are established to assure that regulatory or safety limits are not exceeded for a range of postulated events (transients and accidents).

The safety limit minimum critical power ratio (SLMCPR) is required to protect the fuel design limits with respect to critical power. The SLMCPR is calculated on a cycle-specific basis, because it is necessary to account for the core configuration-specific neutronic and thermal-hydraulic response. It is calculated using a statistical process that considers all operating parameters and associated uncertainties.

The MCPR fuel cladding integrity safety limit ensures that, during normal operation and during AOOs, at least 99.9 percent of the fuel rods in the core do not experience transition boiling. This is accomplished by the determination of a critical power ratio (CPR) margin for transients, which is added to the SLMCPR to determine the operating limit MCPR (OLMCPR). At the OLMCPR, at least 99.9 percent of the fuel rods would be expected not to experience transition boiling during normal operations and transients caused by a single operator error or equipment malfunction.

Using the NRC-approved methods discussed in the Advanced Nuclear Fuels Corporation report ANF-524(P)(A), "Critical Power Methodology for Boiling Water Reactors" (Reference 17), dated November 26, 1990, AREVA performed an SLMCPR assessment for a representative EPU core design at SSES. AREVA indicated that an SLMCPR of 1.07 can be supported at each unit. The licensee will continue to analyze the SLMCPR for each reload in accordance with (1) the above NRC-approved method and (2) the license condition as described in the introduction of this SE. Should the SLMCPR change so as not to remain bounded by the licensed value, the licensee will submit an amendment request for NRC staff review. The thermal and hydraulic design section of this SE (Section 2.8.3) discusses the applicability of the SLMCPR analysis in greater detail.

The MAPLHGR operating limit is based on the most limiting LOCA conditions and ensures compliance with the ECCS acceptance criteria in 10 CFR 50.46. AREVA document EMF-3243(P), "Susquehanna LOCA MAPLHGR Analysis for ATRIUM-10 Fuel and Extended Power Uprate," issued November 2005, presents an evaluation of the ATRIUM-10 MAPLHGR curve for performance during a LOCA starting from EPU conditions at SSES Units 1 and 2 (Reference 18). The NRC staff reviewed this document and determined that its results were obtained by using NRC-approved methods. The staff confirmed that the LOCA analysis supported the referenced MAPLHGR curves through an audit calculation, which showed the limiting criterion to be the PCT. The analysis in EMF-3243(P), as supported by the NRC staff's audit calculations, confirms that the ATRIUM-10 MAPLHGR curve is acceptable. The licensee stated that analyses are performed each reload cycle to ensure that established MAPLHGR limits apply to the new fuel assembly design.

The LHGR limits ensure that the plant does not exceed the thermal-mechanical design limits of the fuel. The licensee stated that the LHGR limits are applicable to the ATRIUM-10 fuel and do not change as a result of CPPU implementation. In accordance with the criteria in SRP Section 4.2, however, AREVA performs analyses of AOOs at the maximum LHGR to determine that, for normal operation and AOOs, fuel centerline melting will not occur. As a result of the analyses, a flow-dependent multiplier is applied to the LHGR thermal limits when the plant is operating at less than 100-percent core flow. The flow-dependent limits and multipliers are established or confirmed each cycle and are based on a conservative flow runup path.

In general, the licensee must ensure that plant operation complies with the cycle-specific thermal limits and specifies the thermal limits in a cycle-specific COLR as required by the plant TS. In addition, while CPPU operation may result in an increase in fuel burnup, the licensee cannot exceed the NRC-approved burnup limits. The licensee stated in Reference 1 that fuel for the uprated, equilibrium core will remain within the NRC-approved exposure limits in Reference 14. A letter from William Ruland, NRC, to James Mallay, Framatome ANP, dated December 17, 2002 (Reference 19), discusses these exposure limits. In its RAI response (Reference 2), the licensee further confirmed that the core designs employing co-resident, pre-CPPU fuel will also comply with these exposure limits.

Conclusion

The NRC staff reviewed the licensee's [[ ]] assessments for SSES Units 1 and 2, and concludes that they are consistent with the methodologies approved for CPPU operation. In addition, the licensee will continue to perform plant- and cycle-specific analyses to confirm that SAFDLs will not be exceeded during the planned cycles. Based on these considerations, 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 EPU and are therefore acceptable to the NRC staff.

2.8.2 Nuclear Design

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 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.

Regulatory Evaluation

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, "Reactor Inherent Protection," 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, "Suppression of Reactor Power Oscillations," 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, "Protection System Functions," 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, "Protection System Requirements for Reactivity Control Malfunctions," 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, "Reactivity Control System Redundancy and Capability," insofar as it requires that two independent reactivity control systems be provided, with both systems capable of reliably controlling 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, "Reactivity Limits," 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. SRP Section 4.3 contains specific review criteria, and Matrix 8 of RS-001 provides other guidance.

Technical Evaluation

Section 4.3 of the UFSAR describes the nuclear design of SSES Units 1 and 2. The safety design bases for the nuclear design include shutdown and excess reactivity, void reactivity coefficient, thermal limits, and stability requirements. This section discusses the NRC staff's review of the reactivity requirements, whereas Section 2.8.1 discusses thermal limits, and Section 2.8.3 addresses stability and void quality modeling.

The higher core energy requirements of a power uprate may affect the hot excess core reactivity and can also affect operating shutdown margins. Based on experience with previous plant-specific power uprate submittals, the required hot excess reactivity and shutdown margin can typically be achieved for power uprates through the standard approved fuel and core reload design process. Plant shutdown and reactivity margins must meet NRC-approved limits established on a cycle-specific basis and are evaluated for each plant reload core. Additional hot excess reactivity and shutdown margin analyses are not specifically required for the EPU.

The licensee stated that reload core design analyses are performed on a cycle-specific basis to ensure that required reactivity margins are maintained. Current TS requirements for cold shutdown margin are maintained at CPPU conditions with ATRIUM-10 fuel by appropriate design of the enrichment and burnable neutron absorber content of the fuel lattices and by judicious placement of fresh and irradiated assemblies in the core. Operation with ATRIUM-10 fuel at CPPU conditions does not change cold shutdown requirements. Current TS reactivity control requirements at the most reactive conditions of the core are met and confirmed using cycle-specific analyses.

The licensee stated in the PUSAR that the code system CASMO-4/MICROBURN-B2 is used to perform the neutronic analyses for the SSES uprated core design. LTR EMF-2158(P)(A), "Siemens Power Corporation Methodology for Boiling Water Reactors: Evaluation and Validation of CASMO-4/MICROBURN-B2," dated October 1999 (Reference 20), describes the evaluation and validation of CASMO-4/MICROBURN-B2. By letter dated May 15, 2007, the NRC staff asked the licensee to demonstrate that the code system was applied in a manner consistent with the validation database presented in EMF-2158(P)(A). The licensee provided information by letter dated June 27, 2007 (Reference 4).

The licensee indicated that CASMO-4 performs a multigroup spectrum calculation using a detailed heterogeneous description of the fuel lattice components. The solution provides pin-by-pin power and exposure distributions, and homogeneous multigroup microscopic cross-sections, as well as macroscopic cross-sections.

MICROBURN-B2 is the core simulator code used by AREVA. The code uses a full three-dimensional pin power reconstruction method. Traversing in-core probe (TIP) and LPRM response models are included to compare calculated and measured instrument uncertainties.

CASMO-4 calculates the microscopic cross-sections and the background nodal macroscopic cross-sections for input to the MICROBURN-B2 nodal depletion calculations. The functional representation of these cross-sections is evaluated from three void depletion calculations with CASMO-4, with instantaneous branch calculations at alternate conditions of void and control state.

At any exposure state, CASMO-4 represents a continuous cross-section over any variation of void fraction using a quadratic fit to the three data points. AREVA performed detailed CASMO-4 calculations for uranium-235 at a spectrum of void fractions to confirm that interpolating a quadratic fit of the three original calculations is an acceptable numerical treatment. The NRC staff agrees that the calculations demonstrate that the quadratic fit approach is acceptable.

This quadratic fit approach is also used throughout depletion to interpolate cross-section changes resulting from spectrum changes and self-shielding. Three quadratic curves are generated from the cross-section library at 0, 0.40, and 0.80 void fractions to demonstrate the behavior of the cross-section as a function of the historical void fraction for each of the tabular instantaneous void fractions. Cross-sections at each of the instantaneous void fractions are then determined for each historical void fraction. These three values are then given another quadratic fit on a single line to plot cross-section as a function of instantaneous void fraction. From this process, a cross-section can be obtained for an instantaneous void fraction with a void history in which both the instantaneous and historical void fractions are different from the 0, 0.40, and 0.80 void fractions explicitly calculated by CASMO-4.

The licensee provided independent CASMO-4 calculations with continuous operation at 40-percent void and branch calculations at 90-percent void to compare with the 0, 0.40, 0.80 approach discussed above and used them as input to the MICROBURN-B2 depletion calculations. The results show excellent agreement with some mild departure at extended burnup. The NRC staff concludes, therefore, that for the range of operating parameters calculated for SSES Unit 1 and 2 CPPU conditions, the use of 0, 0.40, and 0.80 void calculations with mild extrapolation to the predicted maximum exit void fraction is acceptable.

The licensee also provided intermediate cross-section reconstruction comparisons between MICROBURN-B2 and explicit calculations using CASMO-4 at 0.2, 0.6, and 0.9 void fractions, which show excellent agreement as well.

The licensee stated that using explicit cross-section calculations at alternative void fractions that would better envelop the voiding behavior at SSES would introduce more error in intermediate void fractions, which are more prevalent in the EPU core. The licensee provided a comparison of the 0, 0.40, 0.80 quadratic interpolation method to a 0, 0.45, 0.90 interpolation method.

The NRC staff determined that either interpolation method introduces a similar amount of error, but, based on the voiding behavior expected at SSES during CPPU conditions, the error contribution by the 0, 0.40, 0.80 method would be less in total than the contribution of the 0, 0.45, 0.90 interpolation. The calculation error in the voiding range of 0.85–0.90 will increase, but these high void conditions are predicted to occur at less than 1 percent of the total rods in the core. Therefore, the NRC staff concludes that the quadratic fit approach for determining the cross-sections for the depletion calculations is acceptable for CPPU conditions.

The licensee stated further that cycle length and hot excess reactivity are maintained by appropriate selection of initial enrichment, fresh batch size, and burnable neutron absorber design. Sufficient design flexibility exists with the ATRIUM-10 fuel to accommodate operation at CPPU conditions while maintaining adequate power distribution control.

The NRC staff asked in its May 15, 2007, RAI, that the licensee confirm that the CASMO-4/MICROBURN-B2 code system was applied to the uprated core designs in such a manner that the calculational uncertainties were within the ranges specified in EMF-2158(P)(A) and thus approved by the NRC staff. The licensee stated in its June 27, 2007, response that the database for the uncertainty requirements and ranges stated in EMF 2158(P)(A) is drawn from comparisons between measured and calculated TIP responses for each axial level. Gamma scan comparisons, which include both 9x9 and 10x10 AREVA fuel geometries, support the data. The database specifically includes the ATRIUM-10 geometry, which will be used for the CPPU. The licensee stated that there was very good agreement between calculated and measured barium-140 density distributions for both radial and axial values.

In addition to completing an audit to examine the gamma scan data during June 2007, the staff also reevaluated the information provided to the NRC that formed the basis for the staff's original assessment of EMF-2158(P)(A). AREVA performed pin-by-pin scans of ATRIUM-10 fuel among other fuel bundles scanned during this particular gamma scan campaign. The following summarizes relevant details of the gamma scan campaign:

[[

]]

The NRC staff reviewed this information and determined that these features, when combined, subject the fuel to the types of difficult-to-predict fuel depletion conditions that (1) are expected in an uprated reactor and (2) are relevant to the current AREVA fuel design. Section 2.8.7 of this report presents the staff's detailed evaluation of the fuel vendor's gamma scan database.

These gamma scan data are a portion of the database that is used to confirm power distribution uncertainties that are statistically convoluted to determine the fuel cladding integrity safety limit (see Section 2.8.2.1). Therefore, the NRC staff also requested that the licensee evaluate changes in the safety limit that would occur, given increases in the power distribution uncertainties.

The licensee evaluated any sensitivities in power distribution uncertainties that would arise, given (1) increases in the uncertainty response for local power distribution resulting from any possible changes in depletion behavior between SSES and the reactor containing the gamma-scanned fuel and (2) increases in the bundle power uncertainty to account for any differences resulting from the uncertainty observed from the bundle gamma scans in the EMF-2158 database from those predicted at SSES. The licensee has committed to use these increased uncertainty parameters in the cycle-specific SLMCPR evaluation. The SLMCPR discussion in Section 2.8.3.2.1 addresses these uncertainties in greater detail.

The NRC staff concludes, therefore, that the pin-by-pin and core-wide power distribution uncertainties are acceptable for the 10x10 fuel geometry and are acceptable to the uprated conditions anticipated at SSES Units 1 and 2.

The staff has determined that a discussion of the void quality modeling used by AREVA is more appropriate for SE Section 2.8.3, which addresses thermal and hydraulic design. Therefore, this section does not discuss the void quality correlations.

Conclusion

The NRC staff reviewed the licensee's [[ ]] assessments for SSES Units 1 and 2 related to the effect of the proposed CPPU on the nuclear design of the fuel assemblies, control systems, and reactor core. The staff concludes that the licensee adequately accounted for the effects of the proposed CPPU on the nuclear design and demonstrated that the fuel design limits will not be exceeded during normal operation or AOOs, and 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 staff concludes that the nuclear design of the fuel assemblies, control systems, and reactor core will continue to meet the requirements of GDC 10, 11, 12, 13, 20, 25, 26, 27, and 28. Therefore, the NRC staff finds the proposed CPPU acceptable with respect to the nuclear design.

2.8.3 Thermal and Hydraulic Design

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 applies a justified extrapolation from proven designs, (3) provides acceptable margins of safety from conditions that 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 design-basis accident conditions and core thermal-hydraulic stability under normal operation and 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. SRP Section 4.4 contains specific review criteria, and Matrix 8 of RS-001 provides other guidance.

Technical Evaluation

UFSAR Section 4.4 describes the thermal and hydraulic design of SSES Units 1 and 2. The reactor thermal-hydraulic design basis, as stated in the UFSAR, is a requirement to establish the following:

- actuation limits for the devices of the nuclear safety systems such that no fuel damage occurs as a result of moderate frequency transient events

- the thermal-hydraulic safety limits for use in evaluating the safety margin relating the consequences of the fuel barrier to public safety

- that the nuclear system exhibits no inherent tendency toward divergent or limit cycle oscillations, which would compromise the integrity of the fuel or nuclear system process barrier

The first two safety design bases are congruent with GDC 10, and the third is congruent with GDC 12.

The establishment of TS safety limits and core operating limits ensures that SSES Units 1 and 2 will comply with GDC 10. These limits ensure that the thermal and hydraulic design of the reactor, as analyzed by the licensee's fuel vendor, is such that operation of the reactor at CPPU levels will not violate the safety design bases discussed above. The vendor's analysis considers those features of the fuel and reactor having an impact on the thermal and hydraulic performance of the core, including system setpoints, the specific mechanical, nuclear, and thermal and hydraulic design of the fuel, the configuration of plant systems, and similar parameters.

For SSES Units 1 and 2, AREVA performed the analyses on a plant- and cycle-specific basis. The CASMO-4/MICROBURN-B2 code system is used to evaluate cold shutdown margin, SLCS shutdown capability, control rod withdrawal error, loss of feedwater heating (LFWH), CRDA, fuel loading error, and core flow increase event LHGR. The AREVA thermal limits methodology, THERMEX, includes the SLMCPR and OLMCPR determination. XCOBRA is used to evaluate steady-state core thermal-hydraulic performance to supply as input to the SLMCPR calculations. XCOBRA is a steady-state version of XCOBRA-T. The NRC approval of the THERMEX methodology is supplied in XN-NF-80-19, Volume 3, Revision 2 (Reference 21), issued January 1987. Portions of the methodology as described have been updated and replaced with more current methods; for instance, applicable critical power ratio correlations have been replaced. Finally, COTRANSA2 and XCOBRA-T are used to evaluate the transients caused by turbine load reject without bypass, turbine trip without bypass, FW controller failure, inadvertent HPCI actuation, and flow increase from low-power/low-flow conditions.

AREVA safety analyses rely on the [[ ]] drift flux model for predicting the vapor void fraction in the BWR system. The licensee stated that the model has received broad acceptance in the nuclear industry and has been successfully applied to a host of different applications, geometries, and fluid conditions through the application of different parameter correlations.

AREVA uses two different void-quality correlations, depending on the type of analysis performed. For nuclear design, frequency domain stability, nuclear AOO transient, and accident analyses, AREVA uses the [[ ]] void correlation to predict nuclear parameters. For thermal-hydraulic design, system AOO transient and accident analyses, and LOCA analyses, the Ohkawa-Lahey void correlation is used.

Validations of the first correlation were performed that are specific to the ATRIUM-10 fuel geometry. The NRC staff reviewed the data from these validations and determined that the database covers the entire range of normal operating conditions predicted for the SSES uprated core. Because this validation database is specific to the ATRIUM-10 design, and because there is no extrapolation to high void conditions during steady-state operation at SSES, the staff finds that the void-quality correlation has been acceptably applied.

To further consider the propagation of void-quality errors into the overall power distribution, the licensee reevaluated the SSES CPPU cycle depletion [[

]]. In consideration of the two most limiting transients in terms of the ΔCPR (the load reject/turbine trip with no bypass and the FW control failure to maximum demand), the limiting ΔCPR increased by approximately [[

]]

The licensee stated that the ATRIUM-10 void test data were useful in validating void correlation performance in modern rod bundles that include part-length fuel rods, mixing vane grids, and prototypic axial/radial power distributions. Based on its review of the void-quality correlation benchmarking data, the NRC staff also concludes that the proposed CPPU will not change the thermal and hydraulic design of the core in such a manner that the applicability of the validation database for ATRIUM-10 void-quality correlations is unacceptable.

The validation requirements established in EMF-2158(P)(A) provide limiting values for power distribution uncertainties. The NRC staff confirmed that the validation database supporting the uncertainties in use remain applicable, because the database is supported by TIP comparisons and by recent pin-by-pin gamma scan comparisons specifically evaluated for ATRIUM-10 fuel bundles, as discussed in Section 2.8.2 of this SE. The licensee stated that the maximum exit void fraction anticipated for CPPU operation is not expected to exceed the void fractions observed in the EMF-2158(P)(A) benchmark (Reference 20).

The NRC staff finds that the effect of increased uncertainty associated with the application of the void-quality correlation would propagate to the power distribution uncertainties that are determined using the benchmark gamma scan data discussed in Section 2.8.2.2. In addition to the evaluation performed above, the licensee evaluated safety limit sensitivities to possible increases in this uncertainty value and addressed these sensitivities appropriately, as discussed in Section 2.8.3.2.1. The staff finds, therefore, that the validation database covers the range of operation at SSES and that the effects of any possible increases have been accounted for appropriately. The staff discusses the evaluation of the void-quality correlation further in Section 2.8.7 of this SE.

During its audit, the NRC staff requested additional information about the modeling treatment of non-fuel-containing regions of the fuel assembly. Specifically, the staff observed that [[

]]. The NRC staff reviewed the thermal and hydraulic design results for the SSES uprate fuel assemblies and confirmed that, in all analyzed conditions, [[ ]].

Critical Power Ratio Correlation and Safety Limit Minimum Critical Power Ratio

During its review of the applicability of the analysis methods to CPPU operation, the NRC staff discovered that a revision to the CPR correlation of record for both plants, the SPCB correlation, was revised based on certain reductions in conservatism that resulted in assuming the presence of a natural uranium blanket extending above the enriched fuel. The NRC staff requested that the licensee confirm that the fuel designed for uprate operation at SSES Units 1 and 2 would be adequately predicted by the revised CPR correlation, because the proposed blanket length for the uprate fuel would exceed the blanket length assumed in the revision to the CPR correlation.

The licensee responded with a comparison of the revised correlation's predictions for the uprated fuel to the predictions obtained using the CPR correlation as originally approved. Based on differences in boiling length observed on a single pin between the two revisions of the correlations, the NRC staff requested additional clarification. By letter dated July 30, 2007 (Reference 5), the licensee clarified that the observed change was the result of a shift in the most limiting node on the rod, which also caused a change in boiling length. The staff confirmed that, based on the data provided by the licensee, the physical impact resulting from this change would be minimal. The staff concludes that the revised SPCB correlation may be applied to the uprated fuel design with insignificant impact on the critical power prediction. The revised correlation is acceptable for uprated conditions at SSES Units 1 and 2.

The licensee stated that the decrease in SLMCPR for uprate applications can be supported because of reductions in the channel bow as the result of channel replacements. The licensee previously used zirconium-2 fuel channels, which were highly susceptible to control blade shadow corrosion-induced channel bow. In support of CPPU implementation, however, PPL is replacing most fuel channels with zirconium-4 channels. The licensee confirmed that those assemblies that are not re-channeled will be placed at the periphery of the core in nonlimiting conditions. The NRC staff finds this treatment of fuel channel bow acceptable in light of the nonlimiting positioning of the zirconium-2 fuel channels.

The NRC staff reviewed the calculations in support of the reduced SLMCPR for the pre-CPPU cycles and for those after implementation of the CPPU. Except where noted in the following section, the staff confirmed that the core operating strategy to support the CPPU is such that there is little impact on the selection of the SLMCPR value. Although the core will be burned with a flatter power distribution, which would subject more of the fuel assemblies in the core to boiling transition, the flatter power distribution is attained by increasing bundle power for those bundles in the range of 5–6 MWt, whereas the SLMCPR-limiting bundles are operating near 7 MWt. There is a very small increase in the number of bundles operating near the core-wide maximum bundle power.

In further support of the application of the ANF-524(P)(A) (Reference 17) SLMCPR methodology to CPPU operation at SSES, the licensee submitted plant- and cycle-specific uncertainties used in the calculation. The NRC staff approval of ANF-524(P)(A) does not include approval of specific uncertainty values for the calculation; rather, it approves the use of uncertainties, and the document itself lists typical uncertainties. The staff reviewed the uncertainties used at SSES Units 1 and 2 and determined that these uncertainties are consistent both with operation at SSES Units 1 and 2 for CPPU conditions and with the uncertainties listed in ANF-524(P)(A). Variations in the uncertainties remain duly conservative as noted below.

Confirmation of Power Distribution Uncertainties for EPU Conditions

The review of the SSES CPPU includes confirmation that the power distribution uncertainties applied to the thermal limits analyses are valid and applicable for the EPU neutronic and thermal-hydraulic conditions. EMF-2158(P)(A) specifies the power distribution uncertainties applied to the SLMCPR calculations, with the augmentation discussed below.

Review of both the SLMCPR methodology (ANF-524(P)(A)) and the code qualification database contained in EMF-2158(P)(A) indicates that the ATRIUM-10 fuel geometry, including current spacer, part-length rod, and gadolinia loading practices, has been validated through pin-by-pin gamma scans. Bundle power uncertainties have been confirmed through TIP comparisons using recent operational data; however, the source data for the original uncertainty parameters are based on bundle gamma scans obtained from [[ ]]. The applicability of the bundle gamma scans is substantiated by TIP comparisons from databases reflecting current operating strategies (i.e., fuel design, control strategy, power density, and power uprate implementation).

Regarding the adequacy of the validation data for CPPU operation at SSES, the NRC staff notes the following:

- The relevant pin-by-pin gamma scans support the stated predictive capabilities of CASMO/MICROBURN to compute local power distributions under a variety of operating conditions that would be difficult to predict; however, these conditions are not specifically categoric in consideration of the uprated operating conditions predicted at SSES.

- The relevant bundle gamma scans do not reflect the current or proposed fuel loading at SSES, and the NRC staff has opined previously that TIP data, while useful for monitoring core performance, do not form an adequate basis for qualifying neutronic code systems after implementing substantial changes in the core operating strategies.

In response to these concerns, the licensee has proposed applying a statistical treatment to currently available gamma scan data, which has resulted in an increase in power distribution uncertainties applied to the SLMCPR.

To account for potential sensitivities to increases in local peaking factor uncertainty beyond the values reported in EMF-2158(P)(A), the licensee assessed the effect that an increase in local peaking factor uncertainty would have on the SLMCPR. If this uncertainty parameter were increased by [[ ]], the licensee indicated that the net effect would increase the corresponding SLMCPR by approximately [[ ]].

The NRC staff notes that this increase falls below the threshold of concern for increases in SLMCPR. Given that the SLMCPR is licensed to three significant digits (i.e., 1.xx), any increases below 0.005 could be considered negligible. Nonetheless, the staff finds that this uncertainty could effect a necessary increase in SLMCPR when considered summarily with other uncertainty increases.

Therefore, the licensee has committed to use a local power distribution uncertainty that is increased by [[ ]] when calculating the SLMCPR to account for potential increases in local peaking factor uncertainties associated with operational differences at SSES in comparison to those at the reactor that was the source of the gamma scan data. The NRC staff finds that the local power distribution uncertainties, when increased according to the licensee commitments, will provide reasonable assurance that the SLMCPR continues to protect the fuel with respect to the requirements of GDC 10, specifically in consideration of the local power peaking effects expected during uprated operation of the SSES.

To account for potential sensitivities to increases in bundle power uncertainty beyond the values reported in EMF-2158(P)(A), the licensee assessed the effect of reducing the bundle correlation coefficient obtained from the [[ ]]. This statistical treatment represents a [[

]].

The assumption of a reduced bundle correlation coefficient causes an increase in the TIP simulation uncertainty. In consideration of the statistical modeling used to obtain the SLMCPR in accordance with ANF-524(P)(A) and in consideration of the operating characteristics of the SSES units, the NRC staff estimates that this increased uncertainty would effect an approximately [[ ]] increase in the SLMCPR. The staff finds that this uncertainty increase meets the threshold of concern for increases in the SLMCPR. Accordingly, the licensee commits to use the increased bundle power uncertainty in SLMCPR calculations for uprated operations at SSES. The NRC staff finds that the bundle power uncertainties, when increased as committed by the licensee, will provide reasonable assurance that the SLMCPR continues to protect the fuel with respect to the requirements of GDC 10, specifically in consideration of the bundle power effects expected during uprated operation of the SSES.

In accordance with the licensed SLMCPR calculation methodology at the SSES, these increased uncertainties will be factored into the SLMCPR analysis on a cycle-specific basis, and the SLMCPR will be increased as necessary. If the SLMCPR changes such that it is not bounded by the currently licensed value, the licensee will submit an amendment request for NRC review. The NRC staff finds this approach acceptable for the reasons discussed above.

Thermal-Hydraulic Stability

Currently, SSES Units 1 and 2 have implemented the BWROG Long-Term Solution (LTS) Option III Oscillation Power Range Monitor (OPRM). The OPRM system is designed to provide for an automatic scram for the reactor when power oscillations above the system setpoint are detected. The licensee stated that the OPRM hardware [[

]].

The NRC staff reviewed GE LTR NEDO-32465-A, “Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications,” and determined that the hot channel oscillation magnitude portion of the Option III calculation is based on hardware-specific items such as the LPRM assignments and the RPS trip logic. The staff confirmed, therefore, that the hot channel oscillation magnitude portion of the Option III calculation is indeed hardware specific and need not change as a result of CPPU implementation.

The OPRM system is armed only when plant operation is within the Option III trip-enabled region. The Option III trip-enabled region is defined as the region on the power/flow map with power □30-percent OLTP and core flow □60-percent rated core flow, which the licensee stated is expanded as needed. For the CPPU, the Option III trip-enabled region is rescaled to maintain the same absolute power/flow boundaries. As the rated core flow is not changed, the 60-percent core flow boundary is not rescaled; however, the power boundary is rescaled to preserve the 988-MWt monitoring threshold established for the OLTP. Therefore, the new monitoring threshold will be □25-percent CPPU licensed thermal power.

Setpoints for the OPRM system are determined in a two-step process that is based on the MCPR. The MCPR margin that exists before the onset of oscillations is determined for two scenarios—a two recirculation pump trip (RPT) from full power at the highest rod line, and steady-state operation at 45-percent core flow with the core at the operating limit MCPR. From these MCPR values, the change in CPR during an oscillation is assessed to determine the delta over initial CPR versus oscillation magnitude (DIVOM) curve. The licensee stated that the optimum setpoint should be high enough to allow sufficient time for reliable oscillation detection but must be low enough to preclude the violation of the SLMCPR. The setpoint determination is cycle specific.

The licensee relies on the RAMONA5-FA computer code to calculate the critical power ratio response of the core to regional oscillations on a cycle-specific basis. Although the NRC is performing a generic review of the RAMONA5-FA method, SSES was permitted to implement the RAMONA5-FA code system for stability analysis after a 2004 audit determined its acceptability on a site-specific basis. The NRC staff reviewed the DIVOM calculations performed by RAMONA5-FA for differences in predicted CPR response to oscillations between pre- and post-EPU core designs. In response to an NRC RAI (Reference 5), the licensee stated, and the NRC staff confirmed, that the CPR response will undergo no appreciable change resulting from EPU implementation.

The NRC staff finds that, during uprated operation, steady-state and transient voiding in the bypass region may increase so significantly to cause a reduction in sensitivity to the top level of the LPRM system. This reduction propagates error into the OPRM calculation and may effectively reduce the OPRM signal. To assure that the Long-Term Stability Solution Option III protects the fuel adequately under these conditions, it is necessary to set down the OPRM setpoint to account for this potentially decreased signal. Therefore, the licensee has proposed a license condition to set down the OPRM setpoints to account for increased bypass voiding. The staff evaluates this phenomenon and the licensee's proposed condition in SE Section 2.8.7, Additional Review Area—Methods Evaluation. The staff finds that this setpoint setdown will assure compliance with GDC 10, 12, 13, and 20 for the proposed uprated operating conditions. Thus, the OPRM system performance at EPU conditions is supported by current operating experience at the plant, as augmented by prudent, conservative measures, and is therefore acceptable.

The licensee uses the STAIF code to determine limiting channel decay ratio exposures, which are then used for sensitivity studies in RAMONA5-FA. The NRC staff has reviewed and approved the STAIF code. The validation database that supports STAIF is based on decay ratios, which are a measure of the growth of an oscillation. No change in the application of

STAIF results from an EPU; therefore, the staff concludes that the STAIF application at SSES Units 1 and 2 for EPU operation will remain acceptable.

When the OPRM system is inoperable, the plant may use an alternate stability detect and suppress method. The licensee stated that current practice with the Option III system is to use the stability interim corrective actions (ICAs) as the backup method. The ICAs include specific requirements for operator action, as well as restrictions on operation in certain regions of the power/flow map. These ICA regions are validated on a cycle-specific basis using the AREVA STAIF methodology and expanded as necessary.

In light of the information discussed above, the NRC staff concludes that the stability analysis and evaluation performed for SSES Units 1 and 2 will not be unacceptably impacted by the EPU implementation. This conclusion extends to those portions of the stability evaluation that are generic, as well as those aspects that are plant- and/or cycle-specific. The staff discusses the ATWS/instability evaluation in Section 2.8.5.7 of this SE.

2.8.4 Emergency Systems

2.8.4.1 Functional Design of Control Rod System

The NRC staff's review covered the functional performance of the 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.

Regulatory Evaluation

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, "Protection System Failure Modes," 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 that 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, (7) GDC 29, "Protection Against Anticipated Operational Occurrences," 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 the event of AOOs, and (8) 10 CFR 50.62(c)(3), insofar as it requires that all BWRs have an alternate rod injection (ARI) system diverse from the reactor trip system, and that the ARI system have redundant scram air header exhaust valves. SRP Section 4.6 contains specific review criteria.

Technical Evaluation

The SSES comprises two GE BWR/4 plants. GE provides a generic disposition of reactivity control characteristics in the CLTR. The licensee confirmed that the CLTR disposition covers operating conditions at SSES. In the SE approving the CLTR, the NRC staff stated the following:

> Licensees proposing to utilize fuel designs other than GE fuel, up through GE14 fuel, may not reference the CLTR as a basis for their power uprate since the CLTR process applied only to GE fuel and GE accident analysis methods. However, such licensees may reference the CLTR for areas other than those involving reactor systems and fuel issues which are not impacted by the fuel design.

Noting this restriction on the CLTR, the NRC staff reviewed the relevant section of the SE of the CLTR, the licensee's plant-specific justification for using the [[ ]] disposition.

The licensee considered the phenomena affecting the functional design of the CRDS identified by GE in the CLTR. The licensee confirmed that, based on the phenomena identified by GENE, the [[ ]] disposition could apply to SSES Units 1 and 2. In its review, the NRC staff also considered the evaluations in ELTR1 and ELTR2.

The CRDS controls gross changes in core reactivity by positioning neutron-absorbing control rods within the reactor. The CRDS is also required to scram the reactor by rapidly inserting withdrawn rods into the core. The scram, rod insertion, and withdrawal functions of the CRDS depend on the operating reactor pressure and the pressure difference between the CRDS hydraulic control unit (HCU) and the RV pressure above the core plate.

The CRDS was [[ ]] evaluated in Section 5.6.3 and J.2.3.3 of ELTR1 and in Section 4.4 of Supplement 1 to ELTR2. The [[ ]] concluded that the CRDSs for BWR/2–6 plants are acceptable for EPU as high as 20 percent above the original rated power.

This section considers the following topics:

- scram time response
- CRD positioning
- CRD integrity

Control Rod Scram

The licensee stated that CRD scram time response is decreased by the transient pressure conditions. [[ ]] Therefore, the effect of the CPPU is bounded by current response times. The reactor transient pressure does not adversely affect the plant generic scram times for ASME overpressure protection and CPR pressurization transient analyses.

In addition, scram time testing verifies the scram time for individual control rods. The higher pressures that might occur as a result of CPPU operations during isolation events do not have a significant effect on the CRDS scram function.

The licensee has made several notifications concerning channel bow to the NRC under 10 CFR Part 21, “Reporting of Defects and Noncompliance.” In some cases, channel bow can be significant enough to affect the scram response. Therefore, as a part of its review, the NRC staff requested that the licensee provide a discussion of the current status of channel bow at SSES Units 1 and 2.

In response to the NRC staff’s RAI, the licensee stated that PPL has implemented a channel management action plan to monitor and assess the impact of channel bowing on control rod performance. Actions are taken based on the results of the control rod performance tests. Channel bowing can result in an unacceptable operability condition that may ultimately require the replacement of fuel channels in the affected control cells to regain acceptable control rod performance. The susceptible fuel channels are planned to be replaced with new 100–mil, zirconium-4 fuel channels that will have better resistance to channel bow before the CPPU is implemented.

The licensee confirmed that CRD cooling performance remains acceptable for the same reason that CRD positioning remains acceptable.

<u>Control Rod Drive Positioning</u>

The increase in reactor power at the CPPU operating condition results in a [[ ]] The automatic operation of the system flow control valve maintains the required drive water pressure, and the CRD positioning function should not be affected. Regardless, the normal CRD positioning function is an operational consideration and not a safety-related function.

The licensee stated that the CRDS flow control valve maintains the required drive water pressure. The licensee confirmed that the pressure above [[ ]], and that, based on plant operating data, the CRDS flow control valve does not operate near full-open position. It is less than 40-percent open at the current licensed thermal power. On this basis, the licensee concluded that the valve will maintain the required system pressure.

<u>Control Rod Drive Integrity Assessment</u>

GENE indicated that the postulated abnormal operating condition for the CRD design assumes a failure of the CRDS pressure-regulating valve that applies the maximum pump discharge pressure to the CRD mechanism internal components. This postulated abnormal pressure bounds the ASME reactor overpressure limit. The reactor operating condition for a CPPU does not affect the CRD pump discharge pressure. Therefore, the NRC staff agrees with GENE that the CPPU does not affect the maximum calculated stress for the limiting CRD mechanism component.

In its response to the NRC staff’s RAI for the CLTR dated December 18, 2001 (Reference 22), GENE indicated that in those cases where the existing design-basis conditions do not bound

CPPU conditions, a plant-specific evaluation of the CRD mechanism will be performed to account for other applicable design-basis mechanical loads resulting from the RV motion.

On the basis of its review, the NRC staff agrees with the GENE contention that [[ ]] evaluations accounting for design-basis mechanical loads affecting CRD mechanisms provide the basis to ensure that the CRD mechanisms meet design-basis and performance requirements at CPPU conditions.

Technical Conclusion

The NRC staff reviewed the licensee's analyses related to the effects of the proposed EPU on the functional design of the CRDS. The staff concludes that the licensee adequately accounted for the impacts 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 staff further concludes that the licensee has demonstrated that sufficient cooling exists to ensure that the system's design bases will continue to be followed upon implementation of the proposed EPU. Based on this, the staff concludes that the fuel system and associated analyses will continue to meet the requirements of GDC 4, 23, 25, 26, 27, 28, and 29 and 10 CFR 50.62(c)(3) 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 relief and safety valves on the MSLs and piping from these valves to the suppression pool. 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. SRP Section 5.2.2 contains specific review criteria.

Technical Evaluation

Section 5.2.2 of the UFSAR discusses overpressure protection provided by the nuclear pressure relief system. The SRVs provide overpressure protection for the RCPB, preventing failure of the nuclear system pressure boundary and uncontrolled release of fission products. SSES has 16 SRVs that discharge into the suppression pool and, together with the reactor scram function, provide overpressure protection. The SRV setpoints are established to provide the overpressure protection function while ensuring that there is adequate pressure difference (simmer margin) between the reactor operating pressure and the SRV actuation setpoints to prevent unnecessary SRV actuations during normal plant maneuvers.

Since there is no change in dome pressure and simmer margin, no SRV setpoint increase is required and, thus, there is no effect on the SRV opening/closing functionality. The licensee performed the limiting ASME Code overpressure analyses based on 102 percent of the EPU RTP and confirmed that the current SRV setpoints and upper tolerance limits will not change. The ASME overpressure event is evaluated during each cycle-specific reload analysis to demonstrate the adequacy of the pressure relief system. Therefore, the capability of the SRVs to ensure ASME overpressure protection will be confirmed in all the subsequent reload analyses. The NRC staff accepts the licensee's assessment that the SRVs will have sufficient capacity to handle the increased steamflow associated with the operation at the EPU power level.

The design pressure of the RV and RCPB remains at 1250 psig. The ASME Code allowable peak pressure for the RV and the RCPB is 1375 psig (110 percent of the design pressure of 1250 psig), which is the acceptance limit for pressurization events. The most limiting pressurization transient is analyzed on a cycle-specific basis, and this approach would be applicable for each EPU reload cycle. Section 5.5.1.4 of ELTR1 evaluated the ASME overpressure analysis for power uprate to 20-percent power increase. The licensee performed the EPU overpressure protection analysis consistent with the generic analysis in Section 3.8 of ELTR2, which requires ASME Code requirements for overpressure protection, with the NRC staff-approved evaluation model COTRANSA2. The licensee's overpressurization analysis determined that the MSIV closure with scram on high flux is the limiting event. The analysis assumed 102 percent of the EPU RTP and an initial dome pressure of 1050 psig (1064.7 psia). No credit was taken for the MSIV or turbine stop valve position scram, and the two lowest setpoint MSRVs were assumed out of service. The MSIV-position signal scram was assumed to fail, and the high-flux signal scram was assumed to shut down the reactor. The MSIV closure event resulted in a maximum reactor dome pressure of 1298 psig, which corresponds to a vessel bottom head pressure of 1285 psig. Therefore, the peak calculated vessel pressure (1328 psig) remains below the ASME limit of 1375 psig, and the maximum calculated reactor dome pressure remains below the TS safety limit of 1325 psig.

FIV may increase incidents of valve leakage. However, SSES has established administrative limits and actions to address a leaking SRV. The SSES SRVs are dual-function Crosby 6R10 HP 65 BP direct acting valves. In general, FIV may result in an inadvertent SRV opening and a "stuck open" SRV condition. The licensee stated that, for Crosby direct-acting SRV design, this is unlikely based on normal plant operating experience. The licensee also stated that the stuck-open SRV was previously considered in a plant-specific safety analysis and has been demonstrated to be nonlimiting. The plant's off-normal operations procedures address these conditions, regardless of their likelihood.

Increased MSL flow may affect FIV of the piping and SRVs during normal operation. The vibration frequency, extent, and magnitude depend on plant-specific parameters, valve locations, the valve design, and piping support arrangements. The licensee will address the FIV of the piping by vibration testing during initial plant operation at the higher steamflow rates, including the direct vibration monitoring of an SRV.

For the SSES overpressure analysis with equilibrium core, the maximum calculated pressure meets the ASME Code. In addition, the most limiting pressurization transient is analyzed for each EPU reload cycle. Therefore, the NRC staff agrees that the licensee has demonstrated an acceptable analysis of the plant response to overpressure conditions and determined that no plant modifications are necessary. This provides a reasonable assurance that the probability of gross rupture of RCPB or significant leakage throughout its design lifetime will continue to be exceedingly low. Since the operating ranges of RPV pressure and temperature at the EPU conditions remain unchanged, the effect on the RCPB design requirement to behave in a nonbrittle manner to minimize rapidly propagating failures is also unaffected.

Conclusion

The NRC staff reviewed the licensee's analyses related to the effects of the proposed EPU on the overpressure protection capability of the plant during power operation. The 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 staff concludes that the overpressure protection features will continue to meet GDC 15 and 31 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to overpressure protection during power operation.

2.8.4.3 Reactor Core Isolation Cooling System

Regulatory Evaluation

The RCIC system serves as a standby source of cooling water to provide a limited DHR capability whenever the main FW system is isolated from the RV. In addition, the RCIC system may provide DHR necessary for coping with an SBO. The water supply for the RCIC system comes from the CST, with a secondary supply from the suppression pool. The NRC staff's review covered the effect of the proposed EPU on the functional capability of the system. 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, (2) GDC 5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be demonstrated that sharing will not impair their ability to perform their safety function, (3) 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 the event of AOOs, (4) GDC 33, insofar as it requires that a system to provide reactor coolant makeup for protection against small breaks in the RCPB be provided so that the fuel design limits are not exceeded, (5) GDC 34, insofar as it requires that a residual heat removal system be provided to transfer fission product decay heat and other residual heat from the reactor core at a rate such that SAFDLs and the design conditions of the RCPB are not exceeded, (6) GDC 54, insofar as it requires that piping systems penetrating containment be designed with the ability to periodically test the operability of the isolation valves to determine if valve leakage is within acceptable limits, and (7) 10 CFR 50.63, insofar as it requires that the plant withstand and recover from an SBO of a specified duration. SRP Section 5.4.6 contains specific review criteria.

Technical Evaluation

Section 5.4.6 of the SSES UFSAR describes the RCIC system. The SSES RCIC system provides core cooling in the event of a transient where the RPV is isolated from the main condenser concurrent with the loss of all FW flow, and the RPV pressure is greater than the maximum allowable for the initiation of an LP core cooling system.

The SSES RCIC system is located in a seismic Category I structure of the reactor building where it is protected against dynamic effects. The licensee stated that the dynamic effects of pipe whip and jet impingement loads are bounded by the original analysis since pipe whip and jet impingement loads from high-energy pipe breaks are directly proportional to system pressure, which remains essentially the same under EPU at constant pressure conditions. This satisfies the GDC that requires SSCs important to safety to be protected against dynamic effects. The RCIC system also satisfies the GDC that requires SSCs important to safety not to be shared among other nuclear power units.

The RCIC system is designed to maintain sufficient reactor water inventory above the top of active fuel over a wide range of operating pressures to permit adequate core cooling. The scope of the RCIC system evaluation is based on CPPU conditions. The maximum injection pressure for RCIC is conservatively based on the upper analytical setpoint for the lowest available group of SRVs operating in the safety/spring mode. For the SSES EPU, [[

]]

[[

]] Since the performance requirements of the RCIC system are satisfied at EPU conditions, the licensee has satisfied the GDC that require (1) a supply of reactor coolant makeup for protection against small breaks in the RCPB to assure that fuel design limits are not exceeded and (2) residual heat removal to transfer fission product decay heat and other residual heat from the reactor core at a rate such that SAFDLs and the design conditions of the RCPB are not exceeded. Because the RCIC system is unchanged, the GDC that requires maintenance of an extremely high probability of accomplishing safety functions in the event of an AOO continues to be met.

The licensee further stated that at EPU operation, [[

]] The required EPU surveillance testing and system injection demands would occur at the same reactor operating pressures, so there would be no change to existing system and component reliability. The licensee performed an SBO evaluation at CPPU conditions. A single bounding event was analyzed, with the assumption that only the RCIC system was available to control the RPV water level. The licensee stated that the results indicate no change to systems and equipment used to respond to an SBO and that the coping time of 4 hours remains unchanged. The SSES LOFW analysis was performed for a full core of ATRIUM-10 fuel at the EPU conditions. The plant-specific evaluation results indicate adequate water level margin approximately 90 inches above the top of active fuel with only the RCIC available and without operator action.

The RCIC system leak detection devices were not changed because of EPU. Therefore, the system satisfies the GDC that requires that piping systems penetrating the containment be designed with a capability to allow periodic testing of the operability of the isolation valves to determine if valve leakage is within acceptable limits.

Because the licensee analyzed the LOFW transient and SBO event for EPU operation, consistent with the CPPU guidelines, and conservatively evaluated the pressure performance requirements of the SSES RCIC system, [[

]] the NRC staff accepts the

licensee's assessment that the RCIC will continue to meet the NRC's acceptance criteria as described in the preceding Regulatory Evaluation section.

Conclusion

The NRC staff reviewed the licensee's analyses related to the effects of the proposed EPU on the ability of the RCIC system to provide DHR following an isolation of a main FW event and an SBO event and to provide makeup to the core following a small break in the RCPB. The staff concludes that the licensee adequately accounted for the effects of the proposed EPU on these events and demonstrated that the RCIC system will continue to provide sufficient DHR and makeup for these events following implementation of the proposed EPU. Based on this, the staff concludes that the RCIC system will continue to meet the requirements of GDC 4, 5, 29, 33, 34, and 54 and 10 CFR 50.63 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the RCIC system.

2.8.4.4 Residual Heat Removal System

The RHR system is used to cool down the RCS following shutdown. The RHR system is an LP system which takes over the shutdown cooling function when the RCS pressure and temperature are 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 to provide DHR.

Regulatory Evaluation

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, (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, and (3) GDC 34, which specifies requirements for the RHR system.

Technical Evaluation

Section 5.4.7 of the UFSAR describes the RHR system at SSES Units 1 and 2. The RHR system is designed to operate in the following modes:

- shutdown cooling (SDC) mode
- LPCI mode
- suppression pool cooling (SPC) mode
- containment spray cooling (CSC) mode
- FPC mode

[[ ]]
and after the temperature and pressure of the reactor coolant have decreased to the point below which the main condenser can no longer be used as an effective heat sink.

The primary design parameters for the RHR system are the decay heat in the core and amount of reactor heat discharged into the containment during a LOCA. The licensee's UFSAR states that [[

]] Reactor power is independent of fuel design, and use of ATRIUM-10 fuel will have a negligible impact on the vessel water inventory. Therefore, the use of ATRIUM-10 fuel has no impact on the other RHR system modes of operation through CPPU operation.

The CPPU increases the reactor decay heat, which means a longer time is needed to cool down the reactor. [[

]]

By letter dated May 20, 2007, the NRC staff requested that the licensee identify conservatisms in the analysis and clarify whether a more realistic shutdown cooling evaluation would indicate that the RHR system could meet its design objective. In its response (Reference 2), the licensee stated that the shutdown cooling evaluation assumed [[
]]. Although a parametric study was not conducted to determine at what RHR service water temperature would be required to attain the design objective cooling temperature during a shutdown from CPPU conditions, the licensee stated that [[
]] value of RHR service water (RHRSW) temperature would be required. The results of the shutdown cooling evaluation are factored into the outage planning activities.

The LPCI mode is evaluated in concert with the ECCS/LOCA evaluation discussed in Section 2.8.5.6.2 of this SE.

The SPC mode is designed to provide sufficient cooling capacity to ensure that the long-term peak suppression pool temperature following a design-basis LOCA remains within design limits. This mode may be used for normal plant operation during a transient or after a LOCA to remove heat from the containment. The SPC mode is initiated and terminated via remote manual control from the control room.

The proposed CPPU would [[ ]], which increases the heat input to the suppression pool during a LOCA and results in a higher peak suppression pool temperature. Section 2.6 of this SE discusses the effect of the proposed CPPU on the suppression pool after a design-basis LOCA.

The CSC mode provides suppression pool water to the spray headers in the containment to reduce containment pressure and temperature during postaccident conditions. Section 2.6 of this SE discusses the effect of the containment spray on containment.

The FPC assist mode uses the RHR heat removal capacity to provide supplemental fuel pool cooling if the fuel pool heat load exceeds the heat removal capacity of the fuel pool cooling and cleanup system. This mode can be operated separately or along with the fuel pool cooling and cleanup system to maintain the fuel pool temperature within acceptable limits. Standby cooling and cross-ties utilize the standby coolant supply connection and the RHR cross-ties to provide additional long-term redundancy to the ECCSs. The CPPU does not affect this function because the performance requirements for the ECCSs did not change.

Based on its review of the licensee's evaluation and rationale, the NRC staff agrees that plant operation at the proposed CPPU level will have an insignificant impact on the SDC mode of the RHR system discussed above, and therefore, no modifications are necessary. The SE sections indicated provide the staff evaluations of the other RHR modes.

Conclusion

The NRC staff reviewed the licensee's analyses related to the effects of the proposed CPPU on the RHR system. The staff concludes that the licensee adequately accounted for the effects of the proposed CPPU on the system and demonstrated that the RHR system will maintain its ability to cool the RCS following shutdown and to provide DHR. Based on this finding, the staff concludes that the RHR system will continue to meet the requirements of GDC 4, 5, and 34 following implementation of the proposed EPU. Therefore, the staff finds the proposed CPPU acceptable with respect to the RHR system.

2.8.4.5 Standby Liquid Control System

The SLCS provides backup capability for reactivity control independent of the control rod system. The SLCS functions by injecting a boron solution into the reactor to effect shutdown. The NRC staff's review covered the effect of the proposed EPU on the functional capability of the system to deliver the required amount of boron solution into the reactor.

Regulatory Evaluation

The NRC's acceptance criteria are based on (1) GDC 26, insofar as it requires that two independent reactivity control systems of different design principles be provided, and that one of the systems be capable of holding the system subcritical in the cold condition, (2) GDC 27, insofar as it requires that the reactivity control systems have a combined capability, in conjunction with poison addition by the ECCS, to reliably control reactivity changes under postulated accident conditions, and (3) 10 CFR 50.62(c)(4), insofar as it requires that the SLCS be capable of reliably injecting a borated water solution into the RPV at a boron concentration, boron enrichment, and flow rate that provides a set level of reactivity control. SRP Section 9.3.5 contains specific review criteria, and other guidance appears in Matrix 8 of RS-001.

Technical Evaluation

The CLTR provides for a [[ ]] disposition of the SLCS; however, the licensee performed a plant-specific evaluation of the SLCS shutdown capability considering the use of ATRIUM-10 fuel. The licensee also proposed to reconfigure the SLCS for single-pump operation with increased sodium pentaborate isotopic enrichment to meet the injection requirements arising from an increase in predicted peak reactor pressure vessel pressure during postulated ATWS scenarios. The ATWS analysis indicates that the as-analyzed SLCS performance will also preserve the suppression pool temperature design limit of 220 °F. The NRC staff previously found this reconfiguration acceptable in a license amendment dated February 28, 2007 (Reference 23). These modifications were found to be consistent with the guidance provided in

IN 2001-13, “Inadequate Standby Liquid Control System Relief Valve Margin” (Reference 24), dated August 10, 2001.

The licensee stated, and the NRC staff agrees, that the ability of the boron solution to shut down the reactor is not directly related to core thermal power. In fact, the requirements of 10 CFR 50.62(c)(4) are prescriptive rather than hardware specific. The licensee indicated that pending modifications to the SLCS system will preserve compliance with the injection requirements in 10 CFR 50.62(c)(4). The NRC staff reviewed the modifications and associated TS revisions in its previous SE (Reference 23) and found them acceptable.

Based on the considerations discussed above, the NRC staff finds that the SLCS will perform acceptably in CPPU operation.

Conclusion

The NRC staff reviewed the licensee’s analyses related to the effects of the proposed CPPU on the SLCS and concludes that the licensee adequately accounted for the effects of the proposed CPPU on the system and demonstrated that the system will continue to provide the function of reactivity control independent of the control rod system following implementation of the proposed CPPU. Based on this finding, the staff concludes that the SLCS will continue to meet the requirements of GDC 26 and 27 and 10 CFR 50.62(c)(4) following implementation of the proposed CPPU. Therefore, the staff finds the proposed CPPU acceptable with respect to the SLCS.

2.8.5 Accident and Transient Analyses

Regulatory Evaluation

AOOs are abnormal transients that are expected to occur one or more times in the life of a plant. These events are initiated by a malfunction, a single failure of equipment, or a personnel error. The applicable acceptance criteria for the AOOs are based on GDC 10, 15, 20, 25, 26, 27, 28, 31, and 35 in Appendix A to 10 CFR Part 50.

DBAs are not expected to occur but are postulated to occur because their consequences could potentially release significant amounts of radioactive material. They are analyzed to determine the extent of fuel damage expected and to ensure that the radiological dose is maintained within the guidelines of 10 CFR 50.34, “Contents of Construction Permit and Operating License Applications; Technical Information.” The applicable acceptance criteria for DBAs such as LOCAs are based on 10 CFR 50.46, Appendix K to 10 CFR Part 50, and GDC 4, 27, and 35.

The SRP provides the following three review guidelines for evaluation:

(1) Pressure in the reactor coolant and MS systems should be maintained below 110 percent of the design values in accordance with the ASME Code.

(2) Fuel cladding integrity shall be maintained by ensuring that the CPR remains above the MCPR SL.

(3) An AOO should not generate a postulated accident without other faults occurring independently or result in a consequential loss of function of the RCS or reactor containment barriers.

Based on the ANS standards, the reviewer needs to ensure that there is no possibility of initiating a postulated accident with the frequency of occurrence of an AOO.

Technical Evaluation

SSES UFSAR Section 15 describes a wide range of potentially limiting events. A potentially limiting event is an event or an accident that has the potential to affect the core operating and SLs. The plant responses to the limiting transients are analyzed at each reload cycle and are used to establish the thermal limits. In Section 15, the analyses include AOOs in the categories of (1) a decrease in core coolant temperature, (2) an increase in reactor pressure, (3) a decrease in reactor coolant flow rate, (4) reactivity and power distribution anomalies, (5) an increase in reactor coolant inventory, and (6) a decrease in reactor coolant inventory. SSES UFSAR Section 15 also contains the evaluations of DBA events, including CRDA, LOCA, refueling accident, and MSL break accident. It also addresses the radiological consequences of DBAs.

[[

]] to be evaluated in each event category for the EPU core (Appendix E to ELTR1). Among the listed events, the SSES PUSAR evaluated the following transients:

[[

]]

In the PUSAR, the licensee stated that analysis of turbine trip with turbine bypass failure was performed with an equilibrium core of ATRIUM-10. However, the MSIV closure event was the limiting overpressure event, and therefore the results were not presented.

Earlier power uprate applications show that the characteristics of the AOO events that determine the OLMCPR do not change significantly when reactor power is increased up to 120 percent at CPPU operation. The results of the limiting thermal margin analyses depend upon the core design, loading pattern, and other factors and will be reanalyzed for the "actual" EPU core in reload analysis. Thus, this minor deviation of the limiting transient set from ELTR1 is well justified.

The SSES EPU transient and accident analyses used NRC-approved methods. Most transient events are analyzed at the EPU-rated power and maximum permitted core flow state points on the MELLLA power/flow map. To address the 2-percent uncertainty requirement in ELTR1, the licensee stated that [[

]] also accounts for the uncertainties in the COTRANSA2 methodology to compute power and uncertainties in test data. In quasi-steady-state ΔCPR calculations, the uncertainty associated with the initial power is accounted for by using conservative assumptions and conservative inputs]] (Reference 2). Potential limiting events like LOFW, LOCA, and ASME overpressurization events are analyzed at 102-percent rated EPU power for conservatism.

The NRC staff also verified key assumptions made by the licensee for the transient analyses. Two low-bank and two mid-bank SRVs are assumed out of service in the transient analyses. The NRC has reviewed and approved the computer codes used in transient analyses (MICROBURN-B2, HTBAL, XCOBRA, COTRANSA2, XCOBRA-T, and RODEX2), and the licensee has applied them in accordance with the NRC approval. The decay heat model affects the hydraulic response after reactor scram in a transient. ELTR1 requires decay heat no less than ANSI/ANS-5.1-1979 + 10 percent in LOFW transient analysis. SSES employed ANSI/ANS-5.1-1979 decay heat model with two times the standard deviation calculated as defined by the standard [[ ]] in the LOFW analysis (Reference 2). In response to an NRC staff RAI, the licensee recalculated the LOFW transient with ANSI/ANS-5.1-1979 + 10-percent decay heat and confirmed only minor differences in the results. Thus, the NRC staff finds that the ELTR1 decay heat model requirements are satisfied (Reference 5).

A reliable RPS is provided for SSES Units 1 and 2. Two independent reactivity control systems—CRDS and SLCS—are installed. The EPU does not affect the capability to bring the core to subcritical state under any conditions. Thus, GDC 20 and 26 are satisfied.

In summary, the transients analyzed with NRC-approved methodology in the PUSAR can be categorized into three groups—(1) fuel thermal margin events, (2) limiting transient overpressure events, and (3) limiting loss of water level transients. Based on the results in PUSAR Table 9-2, load rejection with no turbine bypass (LRNBP) and turbine trip with no bypass (TTNBP) are the most limiting transients (with ΔCPR of 0.27) in the fuel thermal margin event category. They are used to establish an OLMCPR of 1.34. Thus, the thermal margin transients are acceptable. MSIVF is the most limiting event in the overpressure transient category. Analysis in PUSAR 3.1 shows a maximum reactor pressure of 1328 psig, which is less than the 1375 psig ASME limit. Thus, overpressure transients are acceptable. LOFW flow is the limiting event in the loss of water level transient category. The lowest level inside the core shroud is 90 inches above the top of active fuel. Thus, no core uncovery is expected, and therefore this category of transients is also acceptable.

2.8.5.1 Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steamflow, and Inadvertent Opening of a Main Steam Safety Relief Valve

Regulatory Evaluation

Excessive heat removal causes a decrease in moderator temperature, which 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 margin sufficient to ensure that the design conditions of the RCPB are not exceeded during any condition of normal operation, (3) 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 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. SRP Section 15.1.1-4 contains specific review criteria, and Matrix 8 of RS-001 provides other guidance.

Technical Evaluation

Transients in this category include LFWH, increase in FW flow, increase in steamflow, and inadvertent opening of an MS SRV. Among these transients, LFWH is the most limiting event according to ELTR1. A FW heater can be lost if the steam extraction line to the heater is shut, causing the heat supply to the heater to be removed, producing gradual cooling of the FW heater. In this case, the RV receives cooler FW, which produces an increase in core inlet subcooling. Because of negative moderator temperature feedback, this subcooling increase results in an increase of reactivity and power. A scram on high APRM thermal power may occur.

PUSAR Section 9.1 analyzed LFWH. The calculated ΔCPR is 0.18 (shown in PUSAR Table 9-2), which is bounded by other transients in terms of fuel thermal margin (e.g., TTNBP or LRNPP (ΔCPR of 0.27)). This event is a slow transient, and the pressurization effect is well bounded by other pressurization transients (e.g., TTNBP).

Because GDC 10, 15, 20, and 26 are met, the group of transients is acceptable as summarized in Table 2.8.5.1 below:

Section 2.8.5.1 Events
Table 2.8.5.1

Event	Disposition
LFWH	Evaluated in PUSAR Section 9.1.1
Increase in FW Flow	Nonlimiting event, not analyzed
Increase in Steamflow	Nonlimiting event, not analyzed
Inadvertent Opening of an MS SRV	Nonlimiting event, not analyzed

Conclusion

The NRC staff reviewed the licensee's analyses of the excess heat removal events described above. The NRC staff concludes that 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 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 GDC 10, 15, 20, and 26 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the events stated.

2.8.5.2.1 Loss of External Load, Turbine Trip, Loss of Condenser Vacuum, Closure of Main Steam Isolation Valve, and Steam Pressure Regulator Failure (Closed)

Regulatory Evaluation

A number of initiating events may result in unplanned decreases in heat removal. These events result in a sudden reduction in steamflow 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 margin sufficient to ensure that the design conditions 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. SRP Section 15.2.1-5 contains specific review criteria, and Matrix 8 of RS-001 provides other guidance.

Technical Evaluation

This category of transients includes loss of external load, turbine trip, loss of condenser vacuum, closure of MSIV, and steam pressure regulator failure (closed). [[

]]

[[

]] Section 3.1 of the PUSAR analyzed the MSIVF. The results show a peak reactor bottom pressure of 1328 psig. This pressure is within the acceptance criterion of 1375 psig (ASME Code, 110 percent of design pressure of 1250 psig). Hence, the RCPB design limit is not exceeded. This event is considered an infrequent event instead of an AOO. Thus, MSIVF is not used to establish thermal margin.

Other transients in this group were evaluated to ensure that SAFDLs are not exceeded through establishment of the OLMCPR. Section 9.1 of the PUSAR evaluated LRNBP. In this event, a loss of generator electrical load from high-power conditions initiates a main turbine control valve fast closure. The RPS senses turbine control valve closure and activates the reactor scram. The results of this event show a ΔCPR of 0.27 (PUSAR Table 9-2).

Section 9.1 of the PUSAR also evaluated TTNBP. A variety of turbine or nuclear system malfunctions could initiate a turbine trip. Once initiated, all of the main turbine stop valves close within about 0.1 second. Analysis of TTNBP shows the same results as LRNBP.

These two transients are the limiting events among the analyzed set in PUSAR Table 9-2. They are used to establish OLMCPR (1.34) for fuel thermal limit protection. As long as the OLMCPR is not exceeded, the SAFDLs are not exceeded.

PUSAR Section 9.1 also analyzed LRNBP/TTNBP with RPT failure. This resulted in higher ΔCPR (0.36) and OLMCPR (1.43). It is an AOO with equipment out of service; thus, it is not used to determine OLMCPR for normal operation. For the load reject and turbine trip with turbine bypass events, the ΔCPR (0.22) is bounded by the same events without bypass, as expected since reactor pressurization can be mitigated by turbine bypass.

In addition, PUSAR Section 9.1 analyzed MSIV closure in one of the four steamlines and in all four steamlines. The results show ΔCPR of 0.12 and 0.11, respectively. The events are bounded by LRNBP and TTNBP.

PUSAR Section 9.1 also evaluated the pressure regulator downscale failure event with the backup pressure regulator out of service. The results showed a ΔCPR of 0.29 and an OLMCPR of 1.38. Thus, this AOO with equipment out of service is not used to establish the OLMCPR for normal operation.

Since GDC 10, 15, and 26 are met, the group of transients is acceptable as summarized in Table 2.8.5.2.1 below:

Section 2.8.5.2.1 Events
Table 2.8.5.2.1

Event	Disposition
Loss of External Load/TTNBP	Evaluated in PUSAR Section 9.1; limiting event for OLMCPR
Loss of External Load/ Turbine Trip with Bypass	Evaluated in PUSAR Section 9.1; not limiting
Loss of External Load/TTNBP/ EOC-RPT Out of Service	Evaluated in PUSAR Section 9.1; AOO with equipment out of service and not used to establish OLMCPR for normal operation
Loss of Condenser Vacuum	[[ ]]; not analyzed
Closure of MSIV	MSIV (one valve and all valves) evaluated in PUSAR Section 9.1, bounded by LRNBP and TTNBP MSIVF evaluated in PUSAR Section 3.1; limiting in reactor pressure
Pressure Regulator Downscale Failure	[[ ]], analyzed in PUSAR Section 9.1, determined to be nonlimiting
Pressure Regulator Downscale Failure with Backup Out of Service	Evaluated in PUSAR Section 9.1, AOO with equipment out of service and not used to establish OLMCPR for normal operation

Conclusion

The NRC staff reviewed the licensee's analyses of the decrease in heat removal events described above. The NRC staff concludes that 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 concludes 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 these events. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDC 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 Alternating Current 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 circulation pumps. This causes a flow coastdown as well as a decrease in heat removal, 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 the 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 conditions 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. SRP Section 15.2.6 contains specific review criteria, and Matrix 8 of RS-001 provides other guidance.

Technical Evaluation

The reactor is subject to a complex sequence of events when the station loses all auxiliary power. This can occur if all external grid connections are lost or if faults occur in the auxiliary power system. The TTNBP event bounds this event because the loss of nonemergency ac power event causes a delayed turbine trip with an RPT. The introduced reactivity will be less than in a regular TTNBP. LRNBP and TTNBP, addressed in Section 2.8.5.2.1 of this SE, are acceptable. Therefore, this event is well bounded by other transients.

Also according to the ELTR1 evaluation, loss of auxiliary power to the station auxiliaries is a [[
]]. This event is not analyzed.

Conclusion

The NRC staff reviewed the licensee's analyses of the loss of nonemergency ac power to station auxiliaries event. The NRC staff concludes that 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 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 GDC 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 FW flow could occur from pump failures, valve malfunctions, or a LOOP. LOFW flow results in an increase in reactor coolant temperature and pressure, which eventually requires a reactor trip to prevent fuel damage. Decay heat must be transferred from fuel following a loss of normal FW 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 the 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 conditions 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. SRP Section 15.2.7 contains specific review criteria, and Matrix 8 of RS-001 provides other guidance.

Technical Evaluation

FW control system failure or RFP trip can lead to partial or complete LOFW flow. LOFW flow results in a situation where the mass of steam leaving the RV exceeds the mass of water entering the vessel, resulting in a decrease in the coolant inventory available for core cooling. According to Appendix E.2.2 to ELTR1, the safety criteria for the LOFW flow event (maintenance of adequate transient core cooling) are met by [[
]].

The licensee performed a plant-specific calculation in the PUSAR with a representative equilibrium ATRIUM-10 core for the LOFW flow event following the approach in ELTR1 and ELTR2. This analysis also assumed the failure of the HPCI system and used only the RCIC system to restore the reactor water level. This event is also a test of RCIC capacity.

The increased decay heat because of EPU operation results in a slower reactor water level recovery compared to the CLTP case. The reactor level is automatically maintained above the top of the active fuel without any operator actions. The results show that the minimum water level inside the core shroud is 90 inches above the top of the fuel. The core remains covered throughout the transient, and hence no cladding failure is expected. Based on the level recovery and RCIC performance, this transient is acceptable under the EPU condition.

Conclusion

The NRC staff reviewed the licensee’s analyses of the loss of normal FW flow event and concludes that the licensee’s analyses adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. Additionally, the NRC staff concludes that the loss of a single FW or condensate pump is bounded by the LOFW flow event. 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 FW flow. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDC 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 FW flow event.

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 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 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 conditions 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. SRP Section 15.3.1-2 contains specific review criteria, and Matrix 8 of RS-001 provides other guidance.

Technical Evaluation

Events in this group include recirculation flow control failure, trip of one recirculation pump, and trip of two recirculation pumps. Several varieties of recirculation flow control malfunctions can cause a decrease in core coolant flow. Although the manual loading station output values are adjustable based on selectable high and low limits, it could malfunction in such a way that a zero speed signal is generated for both recirculation flow control loops. This controller failure scenario is no more severe than the simultaneous trip of both recirculation pumps.

Normal trip of one recirculation loop is accomplished through the drive motor breaker. This transient is bounded by the trip of two recirculation pumps.

Trip of both recirculation pumps is mainly caused by a loss of nonemergency ac power. When the drive motor breakers are tripped, the M-Gs will continue to supply some reduced power to their respective recirculation pump motors because of the time required for the M-G sets to coast down. As the core flow decreases, additional core void will form and cause a decrease in reactor power through void feedback. Reactor power will decrease by approximately 50 percent within a short time. The thermal inertia of the fuel will cause thermal power to lag behind the neutron flux and core flow decay. The fuel undergoes a critical power reduction because of a decrease in core flow, but the operating power sustains for a small amount of time. This combination causes the calculated MCPR to decrease to a lower value but not to the SLMCPR. The fuel thermal margin is influenced by the rotating inertia of the M-G sets since it determines the pump coastdown speed.

[[ ]] analyses performed for several BWRs have shown that the events in this category are [[

]] for the EPU evaluation as summarized in Table 2.8.5.3.1 below:

Section 2.8.5.3.1 Events
Table 2.8.5.3.1

Event	Disposition
Recirculation Flow Controller Failure—Decreasing Flow	Nonlimiting event, not analyzed
Trip of One Recirculation Pump	Nonlimiting event, not analyzed
Simultaneous Trip of Both Recirculation Pumps	Nonlimiting event, not analyzed

Conclusion

The NRC staff reviewed the licensee's analyses of the decrease in reactor coolant flow event. The NRC staff concludes that 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 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 GDC 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 Recirculation Pump Rotor Seizure and Reactor Recirculation Pump Shaft Break

Regulatory Evaluation

The events postulated are an instantaneous seizure of the rotor or the break of the shaft of an RR pump. 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 that 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 ensure that the capability to cool the core is maintained, (2) GDC 28, insofar as it requires that the reactivity control systems be designed to ensure 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 (3) GDC 31, insofar as it requires that the RCPB be designed with margin sufficient to ensure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized. SRP Section 15.3.3-4 contains specific review criteria, and Matrix 8 of RS-001 provides other guidance.

Technical Evaluation

Recirculating pump rotor seizure and shaft break are DBAs. Flow through the affected loop is rapidly reduced, leading to a reactor and turbine trip. The recirculation pump rotor seizure is more severe because the pump is assumed to stop instantaneously, which results in a quicker reduction in core coolant flow than a recirculation pump shaft break. The sudden decrease in core flow causes a reduction of core heat transfer. However, core uncovery is not expected during this accident.

[[ ]] analyses performed for several BWRs have shown that the accidents in this category are [[ ]] as summarized in Table 2.8.5.3.2 below:

Section 2.8.5.3.2 Events
Table 2.8.5.3.2

Event	Disposition
Recirculation Pump Shaft Break	Not analyzed, bounded by recirculation pump rotor seizure
Recirculation Pump Rotor Seizure	Not analyzed, bounded by other DBAs

Since the licensee did not propose changes to recirculation pumps, the NRC staff has reasonable assurance that SSES continues to meet the limits during CPPU operation. The RCPB at both SSES units is designed with sufficient margin for this nonlimiting event and is equipped with effective reactivity control systems. Therefore, GDC 27, 28, and 31 are satisfied in terms of pressurization, temperature, and reactivity changes.

Conclusion

The NRC staff reviewed the licensee's analyses of the sudden decrease in core coolant flow events. The NRC staff concludes that 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 concludes that the licensee has 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, the RCPB will behave in a nonbrittle manner, the probability of propagating fracture of the RCPB is minimized, and adequate core cooling will be provided. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDC 27, 28, and 31 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

A malfunction of the reactor control or rod control systems may cause an uncontrolled control rod assembly withdrawal from subcritical or low-power startup conditions. 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 ensure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems. SRP Section 15.4.1 contains specific review criteria, and Matrix 8 of RS-001 provides other guidance.

Technical Evaluation

SSES UFSAR Section 15.4.1.2 describes the rod withdraw error event, a continuous withdrawal of an out-of-sequence rod during a reactor startup from a subcritical or low-power condition. The probability of this event is extremely low because it is contingent upon the failure of the rod worth minimizer (RWM) systems (or the RWM bypassed with a second qualified verifier allowing out of sequence rod selection), concurrent with a high rod worth, out of sequence rod selection contrary to procedures, plus failure of the operator to acknowledge continuous alarm annunciations before to safety system actuation. In a low power range, the RWM will prevent this event from happening by limiting the rod withdrawal according to control rod density and banked position depending on the power level. As described in the UFSAR, the low-power rod withdrawal error events are considered as infrequent and nonlimiting events and are not reanalyzed as part of the reload analysis.

The TS applicability for the RWM for the CPPU is conservatively maintained at the same RTP value as the CLTP value, which results in the RWM enforcing control rod patterns over a greater range. Since this event assumes the failure of RWM, any change of RWM operation related to the EPU does not affect the result of the analysis in terms of reactivity insertion to fuel.

Considering reactivity insertion in this event, OLTP analysis demonstrates considerable margin for the peak fuel enthalpy (60 calories per gram (cal/gm)) to the acceptable limit of 170 cal/gm (for low-power and zero-power rod withdraw error transients, a fuel enthalpy limit of 170 cal/gm is applied). At the uprated power (20 percent more than OLTP) with same initial condition, a higher fuel enthalpy can be expected (20 percent increase from 60 to 72 cal/gm) because of higher enrichment or other changes. But the peak fuel enthalpy should still remain far below the 170 cal/gm limit. EPU operation does not alter the current licensing basis for this event. Thus, it is acceptable.

Conclusion

The NRC staff reviewed the licensee's analyses of the uncontrolled control rod assembly withdrawal from a subcritical or low-power startup condition. The NRC staff concludes that the licensee's analyses adequately accounted for the changes in core design necessary 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 are not exceeded. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDC 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 Positive Reactivity Insertion Event, Continuous Rod Withdrawal during Power Range Operation

Regulatory Evaluation

A malfunction of the reactor control or rod control systems may cause an uncontrolled control rod assembly withdrawal at power. 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 ensure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems. SRP Section 15.4.2 contains specific review criteria, and Matrix 8 of RS-001 provides other guidance.

Technical Evaluation

The rod withdrawal error at power level is categorized as a potential limiting AOO and is reanalyzed for each reload. While operating in the power range, this event assumes that the reactor operator makes a procedural error and fully withdraws the maximum worth control rod. Because of the positive reactivity insertion, the core average power increases. If the rod withdrawal error is severe enough, the rod block monitor will activate alarms and the operator will take corrective actions. The NRC staff finds that, even for extremely unlikely conditions (i.e., for highly abnormal control rod patterns and operating conditions, no acknowledgment of the alarms and the withdrawal continues), the likelihood that the fuel thermal overpower limit and fuel rod mechanical overpower limits would be exceeded is negligible.

The SSES PUSAR analyzed this event at EPU conditions and obtained a ΔCPR of 0.25. The rod withdrawal error event with turbine bypass failure was also evaluated and a ΔCPR of 0.41 was obtained. However, the latter event is an AOO event with equipment out of service; thus, the results are not used to establish the OLMCPR for normal operation.

This category of transient is bounded by other limiting transients according to the value for ΔCPR; thus, it is acceptable.

Conclusion

The NRC staff reviewed the licensee's analyses of the uncontrolled control rod assembly withdrawal at power event. The NRC staff concludes that the licensee's analyses adequately accounted for the changes in core design required 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 are not exceeded. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDC 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 Startup of a Recirculation Loop at an Incorrect Temperature and Flow Controller Malfunction Causing an Increase in Core Flow Rate

Regulatory Evaluation

The startup of an inactive loop transient may result in either an increased core flow or the introduction of cooler water into the core. This event causes an increase in core reactivity because of decreased moderator temperature and core void fraction. 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 ensure 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 initiate automatically 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 margin sufficient to ensure that the design conditions of the RCPB are not exceeded during AOOs, (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, and (5) GDC 28, insofar as it requires that the reactivity control systems be designed to ensure 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. SRP Section 15.4.4-5 contains specific review criteria, and Matrix 8 of RS-001 provides other guidance.

Technical Evaluation

Events in this category include recirculation flow controller failure (increasing flow) and startup of the idle recirculation pump. According to ELTR1, [[

]].

Startup of an idle recirculation pump is a nonlimiting transient for GE BWRs that have the ARTS plant performance option. The NRC has approved SSES for ARTS/MELLLA implementation (Reference 25). Thus, this event is not reanalyzed.

A flow dependent multiplier is applied to the LHGR thermal limits when the plant is operating at less than 100-percent core flow. Flow-dependent thermal power operating limits, MCPR(f) are also developed. These ensure that fuel thermal limits are not violated for the limiting flow increase transients. The flow-dependent limits and multipliers are calculated on a cycle-specific basis and are derived from a conservative two-recirculation-pump slow-flow runout path. For the slow recirculation increase event documented in PUSAR Table 9-2, the OLMCPR is based on MCPR(f); thus, the thermal limits are not violated.

PUSAR Table 9-2 performs the fast recirculation increase event with a more limiting initial condition. The result shows a ΔCPR of 0.13 and an OLMCPR of 1.20. Since the ΔCPR is not limiting compared to other transients, and the OLMCPR is bounded, this event is acceptable. The staff's evaluation of these events are summarized in Table 2.8.5.4.3 below:

Section 2.8.5.4.3 Events
Table 2.8.5.4.3

Event	Disposition
Startup of an Idle Recirculation Loop	Nonlimiting event, not analyzed
Recirculation Flow Controller Failure—Slowly Increasing Flow	Analyzed, nonlimiting event; OLMCPR based on MCPR(f)
Recirculation Flow Controller Failure—Fast Increasing Flow	Analyzed, nonlimiting event; OLMCPR bounded by other events

Conclusion

The NRC staff reviewed the licensee's analyses of the increase in core flow event. The NRC staff concludes that 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 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 GDC 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.

2.8.5.4.4 Spectrum of Rod Drop Accidents

Regulatory Evaluation

The NRC staff evaluated the consequences of a CRDA in the area of reactor physics. The NRC staff's review covered the occurrences that lead to the accident, safety features designed to limit the amount of reactivity available and the rate at which reactivity can be added to the core, the analytical model used for the analyses, and the results of the analyses. The NRC's acceptance criteria are based on GDC 28, insofar as it requires that the reactivity control systems be designed to ensure 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. SRP Section 15.4.9 contains specific review criteria, and Matrix 8 of RS-001 provides other guidance.

Technical Evaluation

Section 15.4.9 of the UFSAR analyzes a CRDA as a DBA. This event assumes that a control rod has been fully inserted. The CRD is assumed to be uncoupled and withdrawn. The problem rod suddenly becomes free and rapidly falls out of core onto the withdrawn drive coupling. The rate of positive reactivity insertion into the reactor core is consistent with the maximum control rod drop velocity. Neutron flux increases and the fuel heats up. Eventually, high neutron flux trips the RPS and the reactor scrams. Additionally, in Section 15.4.9.4 of the FSAR, the licensee stated that no significant pressure increase will result from this event. This is a localized event with no significant change in gross core temperature or pressure, and thus would not cause the applicable ASME Code stress limits to be exceeded.

As stated in the UFSAR, SSES is a banked position withdrawal sequence plant. The peak fuel enthalpy limit for this DBA is 280 cal/gm (for postulated reactivity accidents, a fuel enthalpy limit of 280 cal/gm is applied). The CRDA event is analyzed for each reload. The licensee performed a plant-specific analysis at CPPU conditions using NRC-approved methodology. The results show that the resultant peak fuel enthalpy is 174 cal/gm, which does not exceed the 280 cal/gm limit. Thus, this event is acceptable.

Conclusion

The NRC staff reviewed the licensee's analyses of the rod drop accident. The NRC staff concludes that 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 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 EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the rod drop accident.

2.8.5.5 Inadvertent Operation of the Emergency Core Cooling System or 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 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 the 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 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. SRP Section 15.5.1-2 contains specific review criteria, and Matrix 8 of RS-001 provides other guidance.

Technical Evaluation

SSES PUSAR Section 9.1 analyzed the inadvertent HPCI start event. This transient resulted in a □CPR of 0.18; hence, it is bounded by other limiting transients.

The FW controller failure to maximum demand is [[ ]]. This event starts when the FW flow controller fails to the maximum demand value, which causes a rapid increase in FW flow. The core inlet temperature reduces, positive reactivity is introduced, and power increases. The reactor water level increases until the water-level high setpoint (L8) is reached. When L8 is reached, the main turbine trips, the FW pumps trip, and a reactor scram is initiated as a consequence of the turbine trip.

The results shown in PUSAR Table 9-2 indicate this event (ΔCPR = 0.27) is as limiting as the turbine trip with turbine bypass failure (ΔCPR= 0.27). The SAFDLs are not exceeded, therefore, and this category of events is acceptable.

The same event with a turbine bypass failure generates a ΔCPR of 0.31. However, the FW controller failure to maximum demand /turbine bypass failure is not used to assess the OLMCPR because the event is an AOO with equipment out of service.

Conclusion

The NRC staff reviewed the licensee's analyses of the inadvertent operation of the ECCS or a malfunction that increases reactor coolant inventory. The NRC staff concludes that 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 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 GDC 10, 15, and 26 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the inadvertent operation of the ECCS or a malfunction that increases reactor coolant inventory.

2.8.5.6 Decrease in Reactor Coolant Inventory

2.8.5.6.1 Inadvertent Opening of a 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. The pressure relief valve discharges into the suppression pool. Normally, no reactor trip occurs. The pressure regulator senses the RCS pressure decrease and partially closes the turbine control valves to stabilize the reactor at a lower pressure. The reactor power settles out at nearly the initial power level. The FW control system maintains the coolant inventory using water from the CST via the condenser hotwell. The NRC staff's review covered (1) the sequence of events, (2) the analytical model used for the 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 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. SRP Section 15.6.1 contains specific review criteria, and Matrix 8 of RS-001 provides other guidance.

Technical Evaluation

Inadvertent opening of an SRV will cause a decrease in reactor coolant inventory and result in mild depressurization. The pressure regulator senses the nuclear system pressure decrease and within a few seconds closes the turbine control valve far enough to stabilize RV pressure at a slightly lower value.

This event will have a slight effect on fuel thermal margins. Changes in surface heat flux are expected to be negligible, indicating an insignificant change in the MCPR. [[

]]

Conclusion

The NRC staff reviewed the licensee's analyses of the inadvertent opening of a pressure relief valve event. The NRC staff concludes that 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 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 GDC 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 pressure relief valve event.

2.8.5.6.2 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 RPS and ECCS 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 PCT, total oxidation of the cladding, total hydrogen generation, changes in core geometry, and long-term cooling, (6) functional and operational characteristics of the RPS and ECCS, 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) Appendix K to 10 CFR Part 50, 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 ensure 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. SRP Sections 6.3 and 15.6.5 contain specific review criteria, and Matrix 8 of RS-001 provides other guidance.

Technical Evaluation

Section 15.6.5 of the SSES UFSAR describes the SSES ECCS. ECCS components are designed to provide protection in the event of a LOCA occurring in a rupture of the primary system piping. Although DBAs are not expected to occur during the lifetime of a plant, plants are designed and analyzed to ensure that the radiological dose from a DBA will not exceed 10 CFR 50.67 limits. For a LOCA event, 10 CFR 50.46 specifies design acceptance criteria for (1) the PCT, (2) local cladding oxidation, (3) total hydrogen generation, (4) coolable core geometry, and (5) long-term cooling. Normally, LOCA analyses consider a spectrum of break sizes and locations, including a double-ended rupture of the largest recirculation pipe. Assuming a single failure of the ECCS, the LOCA analysis identifies the break size that will be the most challenging to the reactor and the primary containment. The MAPLHGR operating limit is established on the most limiting LOCA analysis. Licensees perform LOCA analyses at EPU conditions to demonstrate that the 10 CFR 50.46 acceptance criteria can be met.

At SSES, the ECCS includes the HPCI system, the LPCI mode of the RHR, the low-pressure core spray (LPCS) system, and the ADS. The following sections review the systems.

High-Pressure Coolant Injection

The HPCI system is designed to pump water into the RV over a wide range of operating pressures. The primary purpose of the HPCI system is to maintain RV coolant inventory in the event of a small-break LOCA that does not immediately depressurize the RV. In this event, the HPCI system maintains reactor water level and assists in depressurizing the RV.

Section 4.2 of ELTR2 (Reference 9) evaluates HPCI performance [[ ]] for a reactor operating pressure increase up to 75 psi. The [[ ]] evaluation concludes that the HPCI pump and turbine remain within their allowable operating envelopes at EPU condition, the HPCI system is capable of delivering its design injection flow rate, and the turbine has the capacity to develop the required horsepower and speed. The SSES HPCI system was evaluated at EPU conditions. The licensee stated in the PUSAR that there is no change to the maximum specified reactor pressure for HPCI system operation, no change to the HPCI system performance parameters, and no effect on the maximum reactor pressure postulated to be present during system startup. Therefore, no changes are necessary to meet the requirements for the HPCI system or startup controls. Because the maximum normal operating pressure and the SRV setpoints will not change for this EPU, the HPCI system performance will not change. The HPCI system at SSES is [[ ]]

The licensee's ECCS-LOCA analysis (see section below titled, "Emergency Core Cooling System Performance") was based on the current HPCI capability and demonstrates that the system provides adequate core cooling. The NRC staff finds the licensee's assessment that the HPCI system continues to meet the NRC's acceptance criteria at EPU condition acceptable, as outlined in the regulatory evaluation section above.

Low-Pressure Core Spray

The LPCS system is automatically initiated in the event of a LOCA. When operating in conjunction with other ECCSs, the CS system provides adequate core cooling for all LOCA events. The system sprays water into the RV upper plenum after it is depressurized. It provides RV coolant inventory makeup for a large-break LOCA and for any small-break LOCA once the RV has depressurized. It also provides long-term core cooling in the event of a LOCA. For SSES CPPU LOCA events, there is no change in the reactor pressure at which the CS is required to operate.

The ECCS performance evaluation demonstrates that the existing CS system performance capability, in conjunction with the other ECCSs as required, is adequate to meet the post-LOCA core cooling requirement for the EPU conditions. The licensee stated in the PUSAR that the slight change in the system operating condition resulting from the CPPU for a postulated LOCA does not affect the hardware capabilities of the CS system. The CPPU has no effect on the CS distribution in the RV. The CS system at SSES is [[

]]

In further investigations of CPPU effects on CS distribution, the licensee also stated that [[

]] (Reference 2)

The NRC staff, therefore, accepts the licensee's assessment that the EPU does not significantly impact operation of the LPCS system and the SSES LPCS system is [[
]] in Section 4.1 of ELTR2. In addition, the licensee's ECCS-LOCA analysis (see section below titled, "Emergency Core Cooling System Performance") based on the current LPCS capability demonstrates that the system provides adequate core cooling in the EPU

LOCA with expected higher decay heat. Thus, the NRC staff has reasonable assurance that the SSES CS system continues to meet the NRC's acceptance criteria at EPU operating conditions.

Low-Pressure Coolant Injection

The LPCI mode of the RHR system is automatically initiated in the event of a LOCA. The SSES LPCI system has four LPCI pumps, which are divided evenly into two separate trains. Each train injects into one of the two recirculation loops, on the pump discharge side. The primary purpose of LPCI is to help maintain RV coolant inventory for a large-break LOCA and for any small-break LOCA after the RV has depressurized. In the PUSAR, the licensee stated that the LPCI mode at SSES is [[

]]. The NRC staff confirms that the SSES LPCI operating requirements are not affected by SSES CPPU operation and are [[
]].

The licensee's ECCS-LOCA analysis (see section below titled, "Emergency Core Cooling System Performance") based on the current LPCI capability, in conjunction with the other ECCS, demonstrates that the system provides adequate core cooling in the EPU LOCA with expected higher decay heat. Thus, the NRC staff has reasonable assurance that the SSES LPCI system continues to meet the NRC's acceptance criteria at EPU conditions.

Automatic Depressurization System

Section 5.6.8 of ELTR1 provides the ADS evaluation scope. The ADS uses the SRVs to reduce the reactor pressure following a small-break LOCA when it is assumed that the HP systems have failed. This depressurization allows the CS and LPCI to inject coolant into the RV. The ADS actuates either on low water level (L1) plus high drywell pressure or on sustained low water level alone. The plant design requires a minimum flow capacity for the SRVs and that the ADS initiates following confirmatory signals and an associated time delay (120 seconds for SSES). The EPU does not affect the required flow capacity and ability to initiate the ADS on appropriate signals since the ADS initiation logic and ADS valve control are not changed. The licensee stated in the PUSAR that [[

]]

The licensee's ECCS-LOCA analysis (see section below titled, "Emergency Core Cooling System Performance"), based on the current ADS capability, in conjunction with other ECCS systems, demonstrates that the system provides adequate core cooling in the EPU LOCA. Thus, the NRC staff has reasonable assurance that the SSES ADS system continues to meet the NRC's acceptance criteria at EPU conditions.

The EPU operation does not affect the protection provided for the above-mentioned ECCS features (HPCI, CS, LPCI, and ADS) against the dynamic effects and missiles that might result from plant equipment failures.

Emergency Core Cooling System Performance

The ECCS is designed to mitigate postulated LOCAs caused by ruptures in the primary system piping. The ECCS performance under all LOCA conditions and the analysis models must satisfy the requirements of 10 CFR 50.46 and Appendix K to 10 CFR Part 50.

The evaluation model used for SSES LOCA analysis is the EXEM BWR-2000 methodology (Reference 27) approved by the NRC. The EXEM BWR-2000 methodology employs three major computer codes—RELAX, HUXY, and RODEX2—to evaluate the thermal-hydraulics and fuel response during all of the phases of a LOCA event. RELAX (Reference 28) is used to calculate the average core channel and hot channel system response during the blowdown, refill, and reflood phases. HUXY (Reference 29) is used to perform heatup calculations for the fuel rods and local clad oxidation calculation at the axial plane of interest. RODEX2 (Reference 30) is used to determine fuel parameters (such as stored energy) for input to RELAX and HUXY. A complete analysis for a LOCA event starts from the specification of fuel parameters using RODEX2. RODEX2 then determines the initial stored energy for both the hot channel blowdown analysis (RELAX) and the heatup analysis (HUXY). The initial stored energy input to RELAX and HUXY is ensured to be the same as or higher than that calculated by RODEX2 with the specified power, exposure, and fuel design. The thermal-hydraulic response obtained from the RELAX hot channel calculation provides the boundary condition for HUXY to calculate PCT and MWR.

The break spectrum analyses were performed for a core composed entirely of AREVA ATRIUM-10 fuel at beginning-of-life conditions. The calculations assumed an initial core power of 102 percent of the rated EPU value of 3952 MWt, providing a licensing-basis power of 4031 MWt. The 2-percent increase reflects the maximum uncertainty in monitoring reactor power, in accordance with NRC requirements in Appendix K to 10 CFR Part 50. The limiting fuel assembly in the core was assumed to be operated at a MAPLHGR limit of 12.5 kilowatts per foot (kW/ft). The analyses assumed a generic ATRIUM-10 neutronic design that is expected to be conservative and confirmed with each actual cycle-specific design. The analyses were performed at maximum CPPU power and two core flows, 80 million pounds mass per hour (Mlbm/h) and 108 Mlbm/h, which represent the boundaries of a potentially more limiting operating domain (the lowest and the highest attainable core flows at full CPPU power). The results from the analyses of these bounding core flows support operation at intermediate core flows. At full CPPU power, the boundaries of the MELLLA domain are 99 Mlbm/h and 108 Mlbm/h. Therefore, the initial core flows that were analyzed support operation within the currently licensed MELLLA domain because the analysis bounds the MELLLA domain.

The evaluation of past BWR EPUs has shown that an EPU does not affect the limiting break characteristics of a LOCA event, and a small effect on the licensing-basis PCT is expected. Because the EPU has minor PCT change, the limiting single failure is not expected to change for EPU conditions as well. The licensee has performed a complete spectrum analysis of break size (1.0 double-ended guillotine to 0.2 ft^2 split), break locations (recirculation and nonrecirculation pipes), different single failures (battery, LOCA, LPCI, double-ended guillotine, HPCI, and ADS) and axial power profiles (top peaked and mid-peaked) to maximize the PCT.

The results show similar limiting break characteristics as the pre-EPU analyses:

- break size/geometry—double-ended guillotine/1.0 discharge coefficient (1.0 double-ended guillotine) (double-ended guillotine/0.6 double-ended guillotine for pre-EPU)

- break location—recirculation line pump suction

- single failure—LPCI valve
- axial power shape—top peaked

The licensee's analysis of similar break characteristics at both CLTP and EPU licensed thermal power confirms the minor impact of the EPU on LOCA response as expected.

In addition, the PCT obtained at the above-mentioned limiting characteristics was 1844 °F. In Table 6.10 of Reference 18, the licensee showed a PCT of 1945 °F for pre-EPU analysis. The higher pre-EPU PCT results, confirmed by the licensee, resulted from a conservative assumption (i.e., no LPCI into broken loop) (Reference 2). In the EPU calculation, the LPCI flow entered the broken loop in the recirculation pump discharge side and the recirculation discharge isolation valve closed to reduce injection loss. A corresponding calculation at EPU conditions with the same conservative assumption (i.e., no LPCI into broken loop) generated a PCT of 1914 °F, which is still 30 °F lower than pre-EPU. Further licensee investigation indicated that [[

]] (Reference 2). The PCT result shows a substantial margin (350 °F) to the licensing limit of 2200 °F. Thus, the NRC staff finds the PCT result acceptable.

In Table 2-1 of Reference 18, the licensee reported that the maximum local cladding oxidation was 0.8 percent and total hydrogen generation was less than 0.2 percent. SSES ECCS performance can be summarized as follows:

1. PCT 1844 °F, less than 2200 °F
2. Cladding oxidation 0.8 percent, less than 17 percent
3. Hydrogen generation 0.2 percent, less than 1 percent
4. Coolable geometry maintained when criteria 1 through 3 above are met
5. Long-term cooling demonstrated when the core remains flooded to the jet pump top elevation and when a CS system is in operation

According to the 10 CFR 50.46 acceptance criteria, overall ECCS performance is acceptable.

For single recirculation loop operation, a multiplier is applied to the two-loop operation MAPLHGR limits. The application of the appropriate MAPLHGR is to ensure that the expected single-loop operation PCT is less than the calculated PCT for two-loop operation. The single-loop operation analyses are performed at beginning-of-life fuel conditions with a multiplier of 0.8 applied to the two-loop MAPLHGR limit, resulting in a single-loop operation MAPLHGR limit of 10.0 kW/ft. The limiting single-loop operation LOCA is the 3.5 ft^2 split pump suction line break with single failure of LPCI and top-peaked axial power shape. The PCT for this case is 1686 °F (less than 1844 °F), and the results are acceptable.

In summary, the NRC staff accepts the EPU LOCA analyses based on the following six points:

(1) The NRC-approved LOCA methodology is adopted in the plant-specific analysis. The initial conditions, break spectrum, and power profiles selected for LOCA analysis are consistent with the NRC-approved LTR, which covers sufficiently limiting scenarios to reach a maximum PCT.

(2) The licensee concluded that EPU operation does not affect the limiting break characteristics. The NRC staff's RELAP5 confirmatory calculation supports the licensee's evaluation at EPU conditions. The following subsections discuss details of the NRC staff's confirmatory analysis.

(3) The change of predicted PCT for the power-uprated condition is not significant, which is consistent with past EPU review experience. In addition, the predicted PCT contains sufficient margin to the 10 CFR 50.46 acceptance limit.

(4) ECCS performance satisfies the ECCS performance criteria contained in 10 CFR 50.46.

(5) The analyses assume that the hot bundle is operating with a conservatively low OLMCPR and conservatively high MAPLGHR, which the EPU does not change.

(6) Acceptable performance during a LOCA initiating from single-loop operation is ensured when a conservative MAPLHGR multiplier (less than 1.0) is applied to the two-loop MAPLHGR.

Confirmatory Calculation

For reasonable assurance, the NRC staff performed audit calculations, described below, for the SSES PCT.

NRC RELAP5 model

SSES reported the double-ended recirculation line suction break as the limiting LOCA event. The NRC staff performed a RELAP5 (version 3.3) calculation to confirm that the PCT calculated by SSES is reasonably correct and has margin to the 2200 °F SL.

The RELAP5 model used by the NRC staff was based on an existing Browns Ferry, Unit 1, RELAP5 model. Both SSES and Browns Ferry reactors are of the GE BWR4 design. The NRC staff verified, through a response to an RAI (Reference 3), that the vessel and core geometry are similar for both plants with the exception of fuel type and ECCS configuration. SSES has AREVA ATRIUM-10 fuel in the core, whereas Browns Ferry, Unit 1, uses Global Nuclear Fuels GE-14 fuel. Data provided by SSES for the ATRIUM-10 fuel replaced that for GE-14 fuel in the model. The fuel changes include heat structure geometry and coolant hydraulic channel properties, such as hydraulic diameters and heating diameters. For ECCS configuration, SSES LPCI flow is not injected into the intact recirculation loop. Instead, LPCI flow goes into the broken loop recirculation pump discharge side for the limiting break case (single failure—LPCI). The NRC staff incorporated the licensee-supplied HPCI, LPCI, LPCS and ADS flow curves into the RELAP5 model for SSES. The plant initial conditions were modeled to match the initial conditions provided by SSES. These include loop flow, core flow, dome pressure, feed/steamflow, FW temperature, and core inlet subcooling.

The NRC RELAP5 core model for SSES included an average core channel, core bypass channel, and a hot channel with 24 axial cells. The hot channel included the coolant channel box, average rods, and hot rod heat structures. Four assemblies and four hot rods were included in the hot channel. Additional sensitivity studies demonstrated that modeling four hot assemblies does not cause significant PCT variation and has sufficient accuracy for the SSES PCT calculation. The NRC staff kept the axial power shapes in the fuel provided by the licensee the same for the average core channel, hot bundles, and hot rods. The NRC staff verified that the hot bundle power provided by the licensee was accurate through radial peaking factor ([[ ]] for 102% Power/80% Flow (102P/80F) case. The hot rod power was calculated based on the local peaking factor supplied by the licensee. The LOCA calculation was performed at a total core power of 4031 MWt (1.02 x 3951 MWt).

Test Case 1—Limiting Large-Break Loss-of-Coolant Accident Peak Cladding Temperature Confirmation

The NRC staff performed a double-ended guillotine suction recirculation line break LOCA analysis with the same initial condition and boundary conditions. The limiting failure for the limiting analysis is an LPCI valve failure. For a suction line break, this leaves the HPCI pump, two LPCI pumps, one LPCS pump, and the ADS available. The LPCI flows go into the broken loop pump discharge side with the recirculation discharge isolation valve closed. The NRC staff's calculation showed that the limiting PCT is 1816 °F. This limiting PCT result is close to the SSES PCT prediction (1844 °F) in the LOCA report (Reference 18).

Many differences in methodology could contribute to the deviations. One major difference is that the NRC RELAP5 model does not activate the thermal radiation model because of the complex partial length fuel geometry in the fuel assembly. The view factors are complex to model. If radiation heat transfer from fuel rods to the fuel channel box was taken into consideration, the PCT would be lower. In addition, the NRC RELAP5 model is a best estimate model. The RELAP5 code does not fully implement requirements from Appendix K to 10 CFR Part 50 (e.g., 1.2 times the ANS 5-1971 decay heat model, discharge flow model, spray heat transfer coefficient). Thus, the PCT in the RELAP5 calculation would be higher if these conservative assumptions were implemented. The NRC staff finds that the difference in the SSES and NRC PCT calculation is minor. Both calculations suggest an acceptable PCT of 1800 °F, with a safety margin about 400 °F.

Therefore, based on the confirmatory calculation, the NRC staff has reasonable assurance that the SSES EPU licensing-basis PCT (1844 °F) satisfies the acceptance criterion of 2200 °F.

Test Case 2—Large-Break Loss-of-Coolant Accident Break Size Study

The NRC staff also performed a large-break LOCA sensitivity study on the break size to verify that PCT decreases as break size decreases. For a break size of 0.6 double-ended guillotine, a PCT value of 1786 °F was obtained. Compared to SSES results (1673 °F), the NRC calculation is about 100 °F higher. However, the trend of decreasing PCTs with smaller break sizes agrees with the licensee's calculation (from 1844 °F to 1673 °F). The deviation in PCT is relatively minor and can be accounted for by the lack of radiation heat transfer in the NRC model and other model differences. However, the trend is the same, and the PCT is still well below 2200 °F. Therefore, the NRC staff confirmed the trend of large-break PCT as a function of break size.

Test Case 3—Operating Domain (Initial Core Flow) Study

The licensee chose a state point with a reduced core flow (80 Mlbm/h flow) to establish the limiting PCT. The assumption is that this state point will bound the MELLLA flow domain (99 to 108 Mlbm/h) because decreased core flow will increase the downcomer subcooling. The increased downcomer subcooling results in a higher break flow. To ensure the entire MELLLA domain is covered, the licensee also performed a high-flow calculation at 108 Mlbm/hr and obtained a lower PCT (1730 °F). The NRC staff performed a similar calculation with 102-percent power and obtained 108 Mlbm/h and a PCT of 1814 °F. The results are reasonably close. Based on the confirmatory calculation, the NRC staff has reasonable assurance that the PCT in the MELLLA domain is well within the acceptable limit of 2200 °F.

Test Cases 4 and 5—Small-Break Loss-of-Coolant Accident Study

The licensee reported that the limiting small-break LOCA analysis was a single failure—battery 0.7 ft^2 split at the recirculation pump discharge side with 108 Mlbm/h initial core flow. The PCT obtained was 1706 °F, which was about 100 °F lower than the limiting large-break LOCA—a PCT of 1844 °F. The NRC staff performed small-break LOCA calculations with break sizes of 1.0, 0.7, and 0.1 ft^2. The PCTs are 1607 °F, 1602 °F, and 1395 °F, which are 200 °F or more lower than the large-break PCT of 1816 °F. The NRC staff's analysis generally agrees with the trend reported in the LOCA report (Reference 28) that the large-break LOCA is more limiting.

However, the NRC staff also performed a small-break LOCA with a break size of 0.05 ft^2 at the recirculation pump discharge side. The break characteristics included initial core flow of 108 Mlbm/h, 102-percent power, top-peaked axial power profile, and single failure—battery. The PCT obtained was 1940 °F. Based on the initial results, the NRC staff found that the PCT in this break size range (less than 0.1 ft^2) was more limiting compared to the break size at 0.7 ft^2 and therefore requested the licensee to perform additional calculations with the same break characteristics. For the same break size, the licensee's analysis, with a PCT of 1296 °F, indicated that the large-break LOCA scenario still limits the SSES units (Reference 32). Based on the large deviation in PCT prediction, the NRC staff requested additional information, including major parameter plots from the licensee, to understand technical differences between RELAP5 and EXEM/BWR-2000 calculation.

In an August 15, 2007, letter (Reference 6), the licensee discussed the NRC-approved countercurrent flow limitation model that the licensee's fuel vendor employs for LOCA analyses. In the licensee's analysis, the countercurrent flow is evident in the upper part of the hot channel soon after the LPCS starts and contributes to the fuel cooling. The NRC confirmatory analysis showed insignificant countercurrent flow in the hot channel. In light of this technical difference in analysis methods, the NRC staff also requested the licensee to provide the analysis results of the 0.05-ft^2 break size, with the hot bundle being cooled by flooding from the bottom of the bundle rather than the top.

The licensee stated that [[ ]] (Reference 6). Thus, the licensee analyzed the requested 0.05-ft^2 break size by modifying the LPCS injection so that it injected into the bypass rather than the upper plenum. This modification allowed the licensee to take credit for the LPCS coolant makeup volume, which is required to refill the lower plenum, while effectively removing countercurrent flow from the analysis. The licensee's predicted PCT for this scenario was 1460 °F.

After comparing boundary conditions between the two calculations from the RAI response, the NRC staff identified that the RELAP5 calculation underestimated ADS flow in the 0.05-ft^2 break event because of pressurization in the downstream node of the SRV, which reduced the effective ADS flow to the equivalent scenario with two SRVs. After calibrating ADS flow at rated conditions (5 SRVs at full pressure) and adjusting ADS initiation timing based on the RELAP5 collapsed level reaching Level 1, RELAP5 PCT reduced to 1301 °F from 1940 °F. The original calculation (with PCT of 1940 °F) was an extremely conservative analysis based on two SRVs, and a high PCT was expected because of slow depressurization in the reactor and longer core uncovery. The NRC staff also recalculated the 0.7-ft^2 small-break LOCA case with calibrated ADS flow. The deviation was not as significant as the 0.05-ft^2 case because the reactor pressure was much lower for this break size when the reactor level reached Level 1. The ADS flows did not differ significantly before and after calibration.

The NRC staff's calculations agreed well with the licensee's PCT results in small-break LOCA scenarios. The NRC staff calculation reconfirmed that the large-break LOCA limits the SSES EPU LOCA.

Summary

The following table summarizes the PCT comparison between the SSES and NRC models. The NRC staff finds that the PCT obtained by SSES has substantial margin (350 °F) to the acceptable limit of 2200 °F. The NRC staff also independently verified the PCT trends (function of initial flow, break size) found in the SSES LOCA break spectrum analysis (Reference 31). The deviations mainly result from method differences, particularly radiation heat transfer. To estimate the radiation heat transfer contribution to PCT, the NRC staff requested that the licensee perform an additional calculation to [[

]] With similar conservative input for both calculations, the two calculations deviate by approximately 250 °F, which accounts mainly for method differences between two models.

The licensee's calculations, as confirmed by the NRC staff's audit calculations, provide reasonable assurance that, for the EPU, the PCTs comply with the requirements of 10 CFR 50.46.

Test Case	Break Characteristics	SSES PCT (°F)	NRC PCT (°F)
1	102-percent power, 80 Mlbm/h core flow, top-peaked axial power, 1.0 double-ended guillotine suction break, single failure of LPCI	1844	1816
2	102-percent power, 80 Mlbm/h core flow, top-peaked axial power, 0.6 double-ended guillotine suction break, single failure of LPCI	1673	1786

Test Case	Break Characteristics	SSES PCT (°F)	NRC PCT (°F)
3	102-percent power, 108 Mlbm/h core flow, top-peaked axial power, 1.0 double-ended guillotine suction break, single failure of LPCI	1720	1814
4	102-percent power, 108 Mlbm/h core flow, top-peaked axial power, 0.7 ft^2 discharge break, single failure of battery	1706	1510
5	102-percent power, 108 Mlbm/h core flow, top-peaked axial power, 0.05 ft^2 discharge break, single failure of battery	1296 (countercurrent flow) 1460 (countercurrent flow effectively disabled)	1301

Conclusion

The NRC staff reviewed the licensee's analyses of the LOCA events and the ECCS. The NRC staff concludes that 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 concludes that the licensee has demonstrated that the RPS and the ECCS will continue to ensure that the PCT, total oxidation of the cladding, total hydrogen generation, changes in core geometry, and long-term cooling will remain within acceptable limits. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDC 4, 27, and 35 and 10 CFR 50.46 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the LOCA.

2.8.5.7 Anticipated Transients Without Scram

An ATWS is defined as an AOO followed by the failure of the reactor portion of the protection system specified in GDC 20.

Regulatory Evaluation

The regulation specified in 10 CFR 50.62, "Requirements for Reduction of Risk from Anticipated Transients without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants," requires the following:

- Each BWR must have an ARI system that is designed to perform its function in a reliable manner and be independent (from the existing reactor trip system) from sensor output to the final actuation device.

- Each BWR must have an SLCS with the capability of injecting into the RV a borated water solution with reactivity control at least equivalent to the control obtained by injecting 86 gpm of a 13 weight-percent sodium pentaborate decahydrate solution at the natural boron-10 isotope abundance into a 251-inch inside diameter RV. The system initiation must be automatic.

- Each BWR must have equipment to trip the reactor coolant recirculation pumps automatically under conditions indicative of an ATWS.

The NRC staff conducted its review to ensure that (1) the above requirements are met, (2) sufficient margin is available in the setpoint for the SLCS pump discharge relief valve such that the proposed EPU does not affect SLCS operability, and (3) operator actions specified in the plant's emergency operating procedures (EOPs) are consistent with the generic emergency procedure guidelines/severe accident guidelines insofar as they apply to the plant design.

In addition, the NRC staff reviewed the licensee's ATWS analysis to ensure that (1) the peak vessel bottom pressure is less than the ASME Code service level C limit of 1500 psig, (2) the PCT is within the 10 CFR 50.46 limit of 2200 °F, (3) the peak suppression pool temperature is less than the design limit, and (4) the peak containment pressure is less than the containment design pressure. The NRC staff also evaluated the potential for thermal-hydraulic instability in conjunction with ATWS events using the methods and criteria approved by the NRC staff. For this analysis, the NRC staff reviewed the limiting event determination, the sequence of events, the analytical model and its applicability, the values of parameters used in the analytical model, and the results of the analyses.

Technical Evaluation

The ATWS analyses assume that the SLCS will inject within a specified time to bring the reactor subcritical from the hot full-power condition and maintain the reactor subcritical after the reactor has cooled to the cold-shutdown condition. For each cycle, the licensee evaluated how plant modifications, reload core designs, changes in fuel design, and other reactor operating changes affect the applicability of the ATWS analysis of record.

The SLCS at SSES Units 1 and 2 is manually initiated. Because the NRC granted the construction permits for both units before July 26, 1984, the provisions in 10 CFR 50.62(c)(4) requiring automatic initiation of the SLCS system are not applicable.

The licensee stated that SSES Units 1 and 2 meet the ATWS mitigation requirements defined in 10 CFR 50.62 because (1) an ARI system is installed, (2) the boron injection capability is equivalent to 86 parts per million, and (3) an automatic ATWS-RPT function has been installed.
[[

]]

Furthermore, the licensee confirmed that LOOP does not result in a reduction in the RHR pool cooling capability relative to the MSIV closure and pressure regulator failure open cases. With the same RHR pool cooling capability, the containment response for the MSIV closure and pressure regulator failure open cases [[

]]; however, the NRC staff requested that the licensee provide additional information to justify this conclusion.

The licensee stated that the LOOP event is less limiting than the MSIV closure in the short term because of the initiation of recirculation and condensate pump coastdown at time zero, which effectively reduces the severity of the initial power surge. The licensee also stated that the [[ ]] ATWS analysis in ELTR2 has also shown [[ ]] In consideration of this supporting information, the NRC staff accepts the licensee's disposition of the ATWS/LOOP scenario.

The licensee stated that plant-specific ATWS analyses were completed for CPPU conditions, and that the results were acceptable. The licensee further stated that ATWS analyses will be confirmed on a plant- and cycle-specific basis using NRC-approved methods. The NRC staff requested additional information to determine more specifically the assumptions and methods that were used and the results that were obtained.

Analyses were performed in accordance with the approved licensing methodology, "Qualification of the One Dimensional Core Transient Model (ODYN) for Boiling Water Reactors (Supplement 1—Volume 4)," contained in GE LTR NEDC-24154P-A (Reference 58). The NRC staff's acceptance of this model for ATWS analyses does not limit it to GE fuels; in fact, it is currently the only NRC-approved method for BWR ATWS analysis. GE performed the analysis based on a full core of ATRIUM-10 fuel, with fuel-specific input parameters supplied by the licensee. This process does not change as a result of CPPU implementation.

The calculated peak vessel bottom pressure for the CPPU ATWS overpressurization is 1336 psig, which is less than the acceptance criterion of 1500 psig and, hence, is acceptable. Additionally, the licensee stated in Reference 1 that the predicted peak clad temperature is 1434 °F, which is below the acceptance criterion of 2200°F, and is also acceptable.

The NRC staff confirmed that the planned operator actions, which are conservatively bounded in the ATWS analysis, contain steps to protect the core from thermal-hydraulic instability. These steps include power/level control, which directs the operator to reduce the reactor water level. This action reduces the natural circulation and the reactor power. Once the FW sparger is uncovered, the FW injects into steam such that the FW temperature would increase to near saturation. This reduces inlet subcooling, causing a further reduction in power and suppression of power oscillations.

The licensee stated that the operators at the site are trained to respond to an ATWS. In consideration of the operator training provided to protect the plant from an instability during an ATWS, the NRC staff finds that the ATWS performance at SSES Units 1 and 2 is acceptable for EPU conditions. The NRC staff traveled to the site to observe operator actions during simulated ATWS and ATWS/instability scenarios and confirmed, based on these observations, that the ATWS response is consistent with the emergency procedure guidelines.

The NRC staff requested that the licensee justify the [[ ]] disposition of ATWS/instability contained in the power uprate topical reports. In response, the licensee provided an evaluation showing that the power levels required to effect decay ratios of 0.85 and 1.0 at natural circulation condition for the uprated core design fall within the cycle-to-cycle variation at SSES (Reference 2). The NRC staff found this justification acceptable because the particular scenario of concern during an ATWS, with regard to thermal-hydraulic instability, is a dual RPT, which would cause core flow to run back to natural circulation conditions, thus creating a high power to flow ratio and leaving the core susceptible to coupled neutronic and thermal-hydraulic density wave oscillations.

Conclusion

The NRC staff reviewed the information submitted by the licensee related to ATWS and concludes that the licensee adequately accounted for the effects of the proposed EPU on ATWS. The NRC staff concludes that the licensee has demonstrated that ARI, SLCS, and RPT systems have been installed and that they will continue to meet the requirements of 10 CFR 50.62 and the analysis acceptance criteria following implementation of the proposed CPPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to ATWS.

2.8.5.8 Additional Review Area—Station Blackout

Regulatory Evaluation

SBO refers to a complete loss of ac electric power to the essential and nonessential switchgear buses in a nuclear power plant. SBO involves the LOOP concurrent with a 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 source. The NRC staff's review focused on the impact 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 plant's licensing basis. The NRC's acceptance criteria for SBO are based on 10 CFR 50.63. SRP Section 8.1 and Appendix B to SRP Section 8.2 contain specific review criteria, and Matrix 3 of RS-001 provides other guidance.

Technical Evaluation

SSES 1 and 2 was evaluated against the requirements of the SBO Rule, 10 CFR 50.63, using the guidance from NUMARC 87-00 (Reference 32). These guidelines provide a volume of cooling water that must be available, given the site-specific parameters. By letter dated July 30, 2007 (Reference 5), the licensee responded with confirmation that analysis using the recommended condensate inventory calculation presented in NUMARC 87-00 indicates that there is sufficient condensate available in the CST as required by plant TS.

The licensee calculated a required makeup condensate inventory for decay heat removal of 87,418 gallons using the NUMARC 87-00 guidance. This calculated volume is less than the SSES 1 and 2 TS minimum available volume of 135,000 gallons. The licensee stated that NUMARC 87-00, Revision 1, methods only calculate condensate makeup based on decay heat and that it does not include the calculated vessel makeup for steam supplied to the HPCI or RCIC turbines. The licensee stated that both the current and CPPU SBO analyses for SSES 1 and 2 meet and exceed the guidance from NUMARC 87-00, Revision 1. Specifically, the SSES 1 and 2 analyses account for the reactor decay heat, RPV inventory leakage (35 gpm per reactor recirculation pump, 25 gpm for identified drywell leakage, and 5 gpm for unidentified drywell leakage), SRV discharge to the suppression pool (to maintain reactor pressure), and steam supply to the HPCI/RCIC turbines. Therefore, based on the NUMARC analysis method, the licensee concluded that adequate condensate is available, and that that the SBO analysis for SSES 1 and 2 provides a more conservative result than the NUMARC 87-00, Revision 1, analysis.

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. Based on the adequate volume of available condensate as calculated using the guidance in NUMARC 87-00, the NRC staff also concludes that the systems coping performance during an SBO will be acceptable at EPU conditions.

2.8.6 Fuel Storage

2.8.6.1 New Fuel Storage

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. 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 using geometrically safe configurations. SRP Section 9.1.1 contains specific review criteria.

Technical Evaluation

The licensee performed an evaluation to assess the impact of EPU on new fuel storage. The licensee stated that the EPU core design will meet the requirements of the current criticality safety analysis, including the maximum lattice enrichment and minimum gadolinia loadings. The licensee determined that SSES EPU new fuel storage is bounded by the requirements of current licensing basis, and that there is no need to change the licensing-basis requirements for the new fuel storage.

Based on the NRC staff's review of the licensee's [[ ]], the NRC staff concurs with the licensee that plant operation at the proposed EPU level will have an insignificant impact on the fuel storage discussed above, and therefore no modifications are necessary. Since it is not necessary to add or change from the original design or licensing bases, the NRC staff accepts the licensee's assessment that the new fuel storage will continue to meet the NRC's acceptance criteria as delineated in the regulatory evaluation section above.

Conclusion

The NRC staff reviewed the licensee's analyses related to the effect of the new fuel on the analyses for the new fuel storage facilities and concludes that the new fuel storage facilities will continue to meet the requirements of GDC 62 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the new fuel storage.

2.8.6.2 Spent Fuel Storage

Regulatory Evaluation

Nuclear reactor plants include storage facilities for the wet storage of spent fuel assemblies. The safety function of the SFP 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 staff's review covered the effect of the proposed EPU on the criticality analysis (e.g., reactivity of the spent fuel storage array and boraflex degradation or neutron poison efficacy). 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, and (2) GDC 62, insofar as it requires that criticality in the fuel storage systems be prevented by physical systems or processes, preferably by use of geometrically safe configurations. SRP Section 9.1.2 contains specific review criteria.

Technical Evaluation

As discussed in the previous section, the licensee performed an evaluation to assess the impact of EPU on SSES fuel pool storage. On the basis of this assessment, the licensee has determined that for EPU, SSES is bounded by the requirements of the current licensing basis, and that there is no need to change the licensing-basis requirements for the spent fuel storage.

The licensee stated that the enrichment level of the CPPU fuel lattices meets the current criticality safety analysis requirements and that the fuel storage calculations assume the maximum reactivity lattice extends over the entire length of the fuel assembly. As such, the assemblies remain bounded by the current fuel storage criticality analysis. Furthermore, the SFP system is located in the reinforced concrete reactor building. Dynamic effects and missiles that might result from plant equipment failures have not changed with respect to the plant's current design basis, as discussed in the UFSAR Section 3.5.

Based on the NRC staff's review of the licensee's [[ ]], the NRC staff concurs with the licensee that plant operation at the proposed EPU level will have an insignificant impact on the spent fuel storage discussed above, and therefore no modifications are necessary. Since it is not necessary to add or change from the original design or licensing bases, the NRC staff accepts the licensee's assessment that the spent fuel storage will continue to meet the NRC's acceptance criteria as delineated in the regulatory evaluation section above.

Conclusion

The NRC staff reviewed the licensee's analyses related to the effects of the proposed EPU on the spent fuel storage capability and concludes that the licensee adequately accounted for the effects of the proposed EPU on the spent fuel rack temperature and criticality analyses. The NRC staff also concludes that the SFP design will continue to ensure an acceptably low temperature and an acceptable degree of subcriticality following implementation of the proposed EPU. Based on this, the NRC staff concludes that the spent fuel storage facilities will continue to meet the requirements of GDCs 4 and 62 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to spent fuel storage.

2.8.7 Evaluation of AREVA Nuclear Design Methods for SSES Extended Power Uprate

2.8.7.1 Background

In accordance with SRP Section 4.3, the NRC staff has evaluated the SSES EPU core design against applicable regulatory criteria. Given the neutronic aspects of EPU cores relative to previous core designs, the NRC staff performed an evaluation of the applicability of the previously approved nuclear design codes to the neutronic conditions present in the SSES EPU core.

The purpose of this evaluation was to ensure that the field equations, constitutive models, analysis assumptions, and solution techniques embodied in the nuclear design methodologies remain applicable under conditions expected for cycle operation at EPU conditions.

EPU cores are generally designed by flattening the radial core power shape relative to a pre-EPU core. In doing so, the highest power bundle tends to remain the most limiting bundle while other nonlimiting bundles have increased power. To sustain the higher core power level through the same cycle duration, the core must be a high-energy core. A high-energy core has significant reactor physics attributes that differentiate such a design from a pre-EPU, preextended-cycle core.

High-energy cores require high burnable poison loadings. The high loadings are necessary to compensate for the additional excess reactivity necessary to sustain core criticality for the same cycle duration with a higher thermal power. In addition to these high burnable poison loadings, typically, a larger fraction of assemblies are loaded in each cycle to also increase the core cycle energy. High-energy cores are typically depleted in a spectral shift manner to maintain core power while achieving the desired duration.

A combination of higher batch reload fraction and a higher loading of neutron poison, both in the form of burnable poisons and control blades, tends to harden the neutron spectrum during cycle exposure. Additionally, as the average bundle power is increased, the core average void fraction tends to increase. The combination of higher inventories of thermal neutron absorbers, more fissile content, and higher void fractions may result in a hard spectrum that can result in uncertainties in important neutronic parameters over exposures that have not been previously quantified or accounted for based on operating experience in a much softer exposure-averaged neutron spectrum.

Aside from these effects at the bundle level, the increase in total core power will impact the core bypass conditions. During normal operation, a fraction of the fission power is released in the form of radiation, which is directly deposited in the coolant and core structures. The increase in reactor thermal power will result in an increased heat load to the core bypass region, which may result in either lower bypass subcooling or potentially the formation of significant void in the core bypass. The formation of void in the bypass (including the interassembly area and water channels for ATRIUM-10 fuel) has the effect of hardening the neutron spectrum and also may influence the sensitivity of neutron-sensitive instruments in the core bypass region.

2.8.7.2 Phenomenology

2.8.7.2.1 Hard Spectrum Exposure

The spectral conditions present during cycle exposure must be adequately captured in the core neutronic methods to account for the buildup and destruction of principle fissile nuclides and poisons that dictate the core reactivity and power shape. In many cases, small errors in the determination of the neutron spectrum can result in larger errors towards the end of life for a fuel bundle because these errors are propagated through exposure, resulting in a miscalculation in the bundle inventories of principle nuclides.

2.8.7.2.1.1 Gadolinia Pins

High-energy core designs tend to have large loadings of gadolinia burnable absorber in the fuel pins. The pin-wise gadolinia loadings may be high. The very strong thermal neutron absorption cross-section of gadolinia will reduce the nodal reactivity at the beginning of the cycle and suppress power in the loaded pins until the gadolinia has depleted.

At very high loadings, the gadolinia becomes self-shielding. In effect, the gadolinia on the outer surface of the fuel pins absorbs neutrons with such an affinity that thermal neutrons do not appreciably penetrate the fuel pin. This is referred to as the spatial self-shielding effect. Generally, gadolinia depletion is modeled to account for the “onion-skin” effect, where gadolinia in the outer radial regions of the fuel pin depletes at a faster rate than in the inner regions of the pin.

These highly loaded gadolinia pins may reside in lattice locations, such as near water channels, where the liquid bypass water influences the depletion rate of the gadolinia in the outer regions of the fuel pin. If the gadolinia loading is high, the required radial resolution to model the gadolinia depletion rate increases. Predicting higher or lower gadolinia depletion rates has the potential to result in miscalculation of the lattice pin peaking factor near peak reactivity conditions (where the nodal power is expected to be high). The combined effect of miscalculation of the pin peaking factors concurrent with anticipated high nodal power may influence the determination of the thermal margin to limits such as the MLHGR.

The NRC staff has reviewed the technical basis for the acceptance of the CASMO-4/MICROBURN-B2 methodology to adequately determine lattice peaking factors, nodal peaking factors, and gadolinia depletion rates consistently with the established uncertainty analysis for EPU conditions. The NRC staff has evaluated these methods to ensure that the analysis of record adequately demonstrates compliance with GDC 10.

The CASMO-4 methodology is based on a collision probability technique at the pin level in the lattice. An artifact of this method is the presumption on slowing down power in particular regions in a fuel pin cell. In particular cases, special treatment is required for the vanished and empty rods as well as internal water channels. In the water channel in particular, there is a strong slowing down source that may or may not be modeled accurately with a general collision probability method based on assumptions regarding the slowing down power for materials at the center of a cell. In cases where surrounding pins are highly loaded in gadolinia, there may be substantial errors in the gadolinia depletion given the particular sensitivity of this depletion to the local neutron spectrum. These errors would likely manifest themselves as large uncertainties after exposure where gadolinia depletion is miscalculated.

The NRC staff reviewed the qualification of the lattice methods as described in EMF-2158(P)(A) (Reference 20) to address concerns regarding the particular treatment of slowing down in the water channel. The qualification database included pin-by-pin gamma scans at various exposures and various axial levels. The database included various fuel lattice geometries encompassing high gadolinia concentrations. Section 8 of EMF-2158(P)(A) shows the pin-by-pin results. The tables of the pin-by-pin results confirm that the lattice peaking error is not a strong function of the pin location, axial height, or gadolinia content. These results confirm that the treatment of slowing down in the internal water channels for these geometries does not result in a consistent bias in pin peaking factor analytical results with void fraction (as demonstrated by axial level) or proximity to water channels (as demonstrated by the two-dimensional lattice tables). Inadequate treatment of this slowing down power in CASMO-4 would indicate a consistent bias based on gadolinia loading, water channel proximity, or void content in the surrounding fuel pin cells. Since the qualification does not indicate any bias, there is reasonable assurance that the physical modeling of the slowing down process is sufficiently robust to be extended to EPU conditions without detriment to the uncertainty analysis for fuel pin power peaking.

The NRC staff has found that the collision probability technique is adequate to model the thermal and epithermal spectrum collapsing for fuel pins. At the lattice level, geometric features are treated in great detail by using a method of characteristics to solve the two-dimensional flux distribution. The method of characteristics solves the two-dimensional neutron transport equation explicitly along "characteristic" boundaries in the lattice where the neutron transport equation may be solved analytically. This technique allows for accurate solution of the flux distribution that accounts for spatial distortion effects near fuel pin boundaries.

The NRC staff finds that treating the two-dimensional lattice geometry in detail allows for robust modeling of the spatial self-shielding effect in the gadolinia pins. CASMO-4 solves these equations using a large number of energy groups (70 groups) and therefore captures the sharp change in burnable absorber cross-section with neutron energy. Based on the robust solution technique and the qualification benchmark analysis presented in EMF-2158(P)(A), the NRC staff finds that the effect of potentially increased burnable poison loading for bundles in the EPU core design does not impact the uncertainties employed in the SL analysis, and that there is reasonable assurance that the neutronic method will adequately predict pin peaking factors for the gadolinia loaded pins under EPU conditions.

2.8.7.2.1.2 Plutonium Accrual

EPU cores employing spectral shift control strategies will generate a greater amount of plutonium under the hard spectrum exposure conditions than pre-EPU cores on a bundle basis because of the poison hardening effect. Additionally, since the radial core power is flattened, there are fewer low-power bundles, which typically act as moderating zones in the core owing to their low void fraction. Therefore, on a corewide basis, there are fewer sources of thermal neutrons for each higher powered bundle. Hence the core, on average, accrues a larger amount of plutonium under EPU cycle exposure conditions even if the peak bundle power or void fraction decreases relative to pre-EPU conditions.

Plutonium-239 (Pu-239), Pu-240, and Pu-241 are of primary interest. The relative production and destruction rates of these isotopes are driven, predominantly, by low-lying resonances. These are narrow peaks in the cross-section at very low epithermal energies and are typical for higher actinides. The Pu-240 resonance is particularly sensitive to the spectrum. The ratio of the fissile plutonium nuclides to the fertile nuclides has a strong impact on pin peaking late in cycle exposure, particularly when the reactor power shifts upward in the core to those regions of the core additionally exposed under low water density conditions. This ratio also effects average bundle reactivity and nodal reactivity and therefore the prediction of the bundle void distribution and the nodal power distribution. The parameters affected are bundle flow rate (which is a function of the bundle void distribution), the bundle power, and the MLHGR for that bundle. These are relevant to determination of the MCPR, the MLHGR, and the MAPLHGR, and therefore GDC 10.

An uncertainty that increases with depletion drives the contribution to the uncertainty in the SLs. This uncertainty can only be quantified by gamma scans under the applicable conditions. The effect is exacerbated under maximum extended load line limit analysis plus (MELLLA+) conditions where the reduction in core flow at full power would increase the degree of spectral hardening by increasing the core average void fraction further.

The qualification in EMF-2158(P)(A) includes MOX pin gamma scans. These gamma scans indicate that the presence of plutonium at the beginning of irradiation does not contribute to a bias in the pin peaking factors. These MOX data provide reasonable assurance that the energy resolution of the CASMO-4 70-group transport calculation is sufficient to resolve the Pu-240 low-lying resonance capture cross-section for standard void cases. Since the low-lying resonance for Pu-240 is very strong, an error in collapsing the cross-section would result in a noticeable bias in the pin peaking factors for MOX pins under any of the void conditions presented in EMF-2158(P)(A). While the qualification using MOX does not provide an adequate basis for the approval of MOX fuel in SSES, it does provide reasonable assurance that the energy group structure and cross-section libraries in CASMO-4 are sufficiently robust to account for the Pu-240 resonances, even when substantial quantities are present in the fuel.

Furthermore, MICROBURN-B2 models the depletion of the principle actinides using a microscopic tracking method that accounts for the production and destruction of these nuclides explicitly in the core model. The accounting methodology is based on the CASMO-4-generated collapsed microscopic cross-sections and explicitly tracks the accrual of plutonium for nodal-specific historical conditions. The robustness of this explicit technique is evidenced by gamma scan data showing that Quad Cities and KWU-S EOC 13 axial power profiles (pin or bundle) show no bias with axial elevation, which would otherwise be expected given the tendency for plutonium to accrue preferentially in the upper axial extremes of the reactor.

The gamma scan data for axial profiles presented in EMF-2158(P)(A) include specific ATRIUM-10 pin-by-pin gamma scans for spectral conditions similar to operation at EPU conditions. The licensee provided the results of gamma scan measurements for ATRIUM-10 fuel. The gamma scan campaign took place for a once-burnt ATRIUM-10 fuel bundle at the Gundremmingen Unit B (GUN-B) plant in Germany. The Gundremmingen reactors are 3840-MWt uprated BWRs. The gamma scans performed included several pin gamma scans along the axial length of the fuel pin. Several pins were scanned, including gadolinia loaded pins and part length fuel rods. Bundle scans were performed for the axial elevations of the LPRM detectors only.

The scan was performed after one cycle of exposure in the GUN-B, Cycle 13, uprated core. While the ATRIUM-10 fuel had not accrued a significant quantity of plutonium, the gamma scans were performed near the peak reactivity exposure since the gadolinia was depleted for one cycle. The pin-wise gamma scans were performed for the full length of fuel pins, thus characterizing the axial power profiles present on a pin basis. The gamma scans support qualification of the pin-wise depletion modeling based on an accurate prediction of the pin-wise power shapes, hence accurate modeling of gadolinia depletion.

Accurate modeling of the gadolinia depletion following one cycle of exposure at uprate conditions is challenging. The gamma scan campaign comprised not only the ATRIUM-10 bundle but the four-bundle cell, which included two 9x9 bundles and a full MOX fuel assembly. The MOX fuel assembly, because of the large plutonium loading, affects the spectral interaction between neighboring bundles. The spectral gradient model allows for the accurate modeling of this cross-bundle effect, as evidenced by the gamma scan results in EMF-2158(P)(A). The qualification of the MICROBURN-B2 depletion modeling with the qualification of CASMO-4 to generate plutonium cross-sections provides reasonable assurance that CASMO-4/MICROBURN-B2 can likewise model the accrual of plutonium and account for the associated cross-bundle spectral effects.

While the gamma scans were performed after a coastdown, therefore providing information about the axial power shape for periods in the cycle when the reactor power and void fractions were reduced, the ATRIUM-10 test bundle was highly loaded in gadolinia, thereby making the pin-wise distribution of power highly sensitive to the spectral history and pin-wise depletion rates over the first cycle of exposure. The qualification provides reasonable assurance that the pin-wise depletion modeling capabilities in MICROBURN-B2 can acceptably predict the pin-wise and nodal nuclide concentrations through exposure up to the point of the scan.

The first cycle exposure campaign for ATRIUM-10 demonstrates that there is no increase in the nodal or pin-wise power distribution uncertainties relative to those values in EMF-2158(P)(A) for OLTP cores. The results of the gamma scan demonstrate that there are no ATRIUM-10-specific design features that result in biases in the computational predictions of bundle or pin power distribution. The gamma scan campaign is particularly challenging to model given the presence of a 9x9 MOX fuel bundle in the four-bundle set that was scanned at EOC 13 (References 44 and 53).

The ATRIUM-10 gamma scan campaign provides reasonable assurance that the historically determined accuracy for the CASMO-4/MICROBURN-B2 code suite remains applicable to the modern fuel design as operated in high power density cores. In summary, acceptance of the historically determined uncertainties is based on the challenges inherent to the modeling of the KWU-S ATRIUM-10 bundle; namely, the bundle was—

- an ATRIUM-10 bundle (specific geometry accounted for)
- exposed in an uprated BWR core (hard-spectrum conditions)
- adjacent to MOX-loaded bundles (cross-bundle spectral interactions)
- loaded with 11 gadolinia rods (high burnable poison loading)
- scanned after one cycle of exposure (to confirm gadolinia depletion models)

A comparison of the spectral index (the ratio of fast to thermal flux) shows that the KWU-S spectral conditions for various axial locations remain softer than the spectral index anticipated for the SSES EPU core. This is caused, in part, by the lower gadolinia loading and enrichment in the ATRIUM-10 bundle in the KWU-S core as well as the EOFPL coastdown. Therefore, the NRC staff finds that the gamma scan data do support the robustness of the method but do not serve adequately to justify the use for SSES EPU conditions of those uncertainties previously established during the Quad Cities EOC 1 and EOC 3 gamma scan measurements.

Based on the robust isotopic tracking method and spectral collapsing methods in the CASMO-4/MICROBURN-B2 code, the NRC staff finds that there is reasonable assurance that under the harder spectrum the uncertainty in pin and bundle powers would not increase by a factor greater than [[ ]]. The licensee has adjusted the bundle power uncertainty in the SLMCPR methodology to account for any additional uncertainty as a result of increased spectrum hardness under exposure. The licensee has adopted an increase in the bundle power uncertainty considering a [[ ]] reduction in the cross-bundle spectral interaction correlation parameter.

During normal operation, the powers of the bundles surrounding a TIP instrument are determined based on the cross-bundle correlation. The data supporting the cross-bundle correlation are based on the Quad Cities gamma scan campaign. While gamma scans were not performed along the bundle axially in the KWU-S EOC 13 gamma scans, accurate modeling of the radial power distribution in the selected pin scans, both in the MOX bundle and in the ATRIUM-10 bundle, serve to demonstrate the ability of the code to model complex cross-bundle neutron current distributions and spectra. The data presented in EMF-2158(P)(A) indicate that there was no noticeable degradation in the bundle power distribution determination for the ATRIUM-10 or MOX bundles given particularly challenging analysis conditions.

The NRC staff therefore finds that a penalty to the bundle power distribution based on a [[ ]] change in the cross-bundle correlation modeling is sufficiently large to adequately capture any additional uncertainties based on the extension of the methods to higher spectral indices. The resultant bundle power uncertainty used in the SLMCPR determination is increased from 2.34 percent to 2.78 percent and is applied in each cycle calculation. The NRC staff finds that this penalty is acceptable to cover any additional uncertainty as it conservatively assumes that future gamma scan campaigns would indicate 1000percent error in the cross-bundle correlation, which the sparse KWU-S EOC13 gamma scans indicate would not be the case for a harder spectrum, with modern fuel, and including a MOX bundle. Therefore, the NRC staff finds that the basis is adequately conservative and acceptable.

However, under reduced flow conditions, such as MELLLA+ conditions, the spectrum will harden relative to the EPU conditions and the extension of this methodology will require additional NRC staff review and approval before being applied; (SSES is currently licensed to MELLLA, but may request a license change to apply MELLLA+ in a future application).

2.8.7.2.2 Control Blade History

An adequate control rod history model must be included to account for long durations of exposure of the fuel under partially controlled conditions. The control blade insertion suppresses power sharply along the fuel lattice. During exposure, half of the lattice experiences reduced exposure while the other half experiences a greater degree of (1) power peaking, (2) actinide and poison depletion, and (3) nonuniform radial void distribution.

When a control blade is then withdrawn, the power will shift to the previously controlled region of the bundle. This may result in more dramatic pin peaking if that region of the bundle was not heavily poisoned with gadolinia. While branch analyses are typically performed using both controlled and uncontrolled histories, the pin peaking factors must account for the history effect. To summarize the history effect, the longer the fuel bundle is exposed under controlled conditions the higher the immediate peaking will be once the blade is withdrawn; but the longer it is exposed at uncontrolled conditions following the blade withdrawal the lower the pin peaking will be. There is a memory effect in the lattice behavior when control conditions change. Inappropriate modeling of the control blade history effects for the plant-specific control strategy can result in large errors in local peaking factors, particularly following the withdrawal of deep blades.

The errors in pin peaking would compound with bundle exposure and affect the adequacy of the MLHGR determination and the determination of the two-dimensional peaking factors used in the MCPR calculation. Therefore, the NRC staff reviewed the acceptability of the AREVA nuclear design method to demonstrate compliance with GDC 10.

MICROBURN-B2 includes an approved pin power reconstruction model, described in greater detail in EMF-1833(P), Revision 2, "MICROBURN-B2: Steady State BWR Core Physics Method," issued September 1998 (Reference 45). This model includes both a radial flux gradient model to account for gross radial tilting of the local flux as a result of control blade insertion as well as nodal burnup and spectral history correction models.

The nodal burnup gradient model accounts for the exposure history effect on radial pin power peaking within a bundle. The burnup history is used to accurately model nodal parameters during controlled exposure. The model works by tracking nodal surface power and exposure, determining surface and corner flux and currents, and using a sophisticated weighting scheme to superimpose the face and corner flux distributions on the infinite lattice power distributions to determine the two-dimensional distribution of power and exposure in the node on a pin basis.

Similarly, the spectral gradient allows for accurate modeling of nuclear parameter evolution through cycle exposure with changing flux spectra. The spectral gradient model adjusts the slowing down cross-section on a nodal level to explicitly account for the nodal ratio of fast to thermal flux. The spectral history model adjusts the nodal cross-sections to account for the cross-bundle neutron leakage that can affect the nodal neutron flux spectrum. These models make the MICROBURN-B2 code specifically suited to calculate radial pin power distributions for high-energy cores (with large blade densities) under EPU conditions (with higher core average void, hence larger Fermi ages).

The NRC staff finds that the qualification of the MICROBURN-B2 pin power reconstruction, nodal burnup, and spectral gradient models described in EMF-2158(P)(A) (Reference 20) provides an adequate basis to demonstrate that these models accurately represent the intended neutronic phenomena. The qualification includes a significant assessment of TIP comparisons for spectral shift control strategy cores. In these comparisons, the TIP measurements are most sensitive to those pins furthest from the control corner. The pins furthest from the control corner are also highly sensitive to the history effect from control blade insertion on the gross bundle radial power distribution. Therefore, the qualification provides a basis for the acceptance of the methodology in cases where large radial gradients are present across the bundles. To a certain extent, the higher core average void fraction present in EPU core designs will enhance neutronic coupling between nodes and flatten the bundle radial flux distribution. Therefore, the NRC staff finds that the inclusion of the models provides a basis for the extension of the MICROBURN-B2 method to EPU conditions for SSES.

However, the implementation of a MELLLA+ operating domain will reduce flow in the peak and average power fuel bundles. Under EPU conditions, the relative increase in flow resistance in the average bundle results in a somewhat increased flow rate in the EPU core design hot bundle relative to an OLTP core design. The reduction in flow for MELLLA+ conditions may result in sharper radial flux gradients across a bundle based on two-dimensional flow distributions within the bundle that cannot be explicitly quantified at this point. Specific MELLLA+ rod patterns may or may not result in flow reductions where the assumption of uniform flow results in errors that are not negligible compared to previously established values. Therefore, application of the proposed methodology to MELLLA+ conditions above the MELLLA high flow control line will require separate review and approval of the neutronic methods to adequately account for radial bundle effects in the determination of SAFDLs.

2.8.7.2.3 Flattened Radial Core Power Shape

The NRC staff reviewed the adequacy of the nuclear design methods for the calculation of neutronic parameters for downstream stability analyses. Generally, flattening the radial core power is achieved by loading higher power bundles closer to the core periphery such that the number of limiting bundles remains similar to the OLTP core designs. The effect is to produce a dramatic shift in the core radial adjoint outwards towards the periphery. This shift of the adjoint function outward results in a smaller eigenvalue separation between the fundamental and first harmonic neutron flux modes. In essence, void perturbations in radial locations near the harmonic peak have a greater impact on the core eigenvalue because these bundles have a higher neutronic importance based on the EPU core design relative to a standard OLTP core design.

The decreased eigenvalue separation results in a core design that is generally more susceptible to regional mode oscillations under reduced core flow conditions. GDC 12 requires that oscillations that can result in exceeding SAFDLs are either prevented or readily detected and suppressed. For the SSES EPU core, a dual RPT AOO would result in unstable conditions along the natural circulation line of the power to flow map.

The detect and suppress solution (DSS) is based on LTS Option III. The Option III LTS DSS uses LPRM indications to determine the oscillation magnitude for regional mode oscillations. The signals are fed to the OPRM, which will initiate a reactor scram once a particular setpoint is reached. The setpoint is determined based on an analysis of the severity of a regional mode oscillation. The oscillation severity is determined in terms of the transient change in CPR for an oscillation of a particular magnitude and correlation according to the DIVOM curve. The DIVOM curve is calculated according to the RAMONA5-FA methodology with neutronic input from MICROBURN-B2. RAMONA5-FA is a three-dimensional neutron kinetics code with one-dimensional thermal-hydraulic representations for the reactor core and vessel components.

At EPU conditions, the higher core power results in an additional heat load to the bypass from direct moderator heat. The direct moderator heat is deposited in the bypass essentially instantaneously following the fission event that released the prompt neutrons and gammas. In general, roughly 10 to 15 percent of the energy released in fission is in the form of direct energy. Of the direct energy, a large fraction (approximately 70 percent) is prompt (being released and deposited at the time of fission). This energy is deposited directly in the moderator or core structures and subsequently removed by the moderator. A detailed heat balance reveals that the bypass flow rate is approximately 10 percent of the total core flow, thus removing direct energy deposited in the interassembly regions and water flowpaths internal to the channel (e.g., water channels).

In the event of a dual RPT or other recirculation flow-reduction AOOs, the core active channel and bypass flow are both reduced. Before the initiation of an oscillation, the core bypass region is typically closer to saturated conditions at lower axial elevations for the EPU core relative to the OLTP core design. If there is an oscillation under these conditions, it is possible for the instantaneous prompt radiation released from a pulse along the harmonic flux shape to result in flashing (increased voiding) in the bypass around the peak oscillating bundles. In this situation, the LPRM instrument sensitivities may be decreased because of the presence of void in the bypass.

If an oscillation reduces the LPRM instrument sensitivity proportional to the magnitude of the oscillation, then the LPRM signals may indicate an oscillation magnitude that is lower than the actual magnitude of the oscillation in neutron flux and therefore radial power. If bypass voiding is found to occur, the approved NEDO-32465-A (Reference 48) does not provide adequate protection against cladding failure from transition boiling for regional mode oscillations during reduced recirculation flow AOOs. The NRC staff evaluated the adequacy of the LPRM instruments to provide indication of the neutron flux against GDC 13.

The NRC staff reviewed analyses performed by the licensee to determine (1) if bypass voiding occurs to a significant extent at LPRM locations under reduced recirculation flow AOOs, or (2) consideration of the effects of bypass voiding were adequately included in the determination of the OPRM setpoint based on the DIVOM curve analysis for SSES.

According to the Option III LTS DSS, the oscillation magnitude is determined based on LPRM string measurements of the neutron flux. The oscillation magnitude is based on the peak, minimum, and average LPRM indications. In cases where the bypass is significantly voided at the onset of instability or during periods of peak flux, the oscillation magnitude as determined based on LPRM signals may not represent the actual oscillation magnitude since the LPRM sensitivity is a strong function of the bypass void fraction.

If the prompt direct energy deposited in the bypass during a neutron flux pulse does not increase the bypass void fraction, then the OPRM reduced sensitivity would be effectively normalized in the determination of the normalized oscillation magnitude. The oscillation magnitude is measured for each OPRM channel and is based on the peak divided by average signal during the transient.

Therefore, the NRC staff finds that consideration of reduced sensitivity when the bypass void fraction at the LPRM level D detectors is constant is not necessary to preserve the efficacy of the OPRM to suppress regional mode oscillations. In response to NRC staff concerns regarding efficacy of the LPRM level D detectors under transient conditions, the licensee provided a technical basis for the continued applicability of NEDO-32465-A (Section 2.8.5.7.2 of the SE summarizes the basis).

AREVA stated that the bypass voiding issue does not adversely affect the capability of the OPRM for two reasons. First, the combination of the axial signals is inherently desensitizing because of phase lag. Second, the reduction of the relative contribution from the LPRM level D detectors (as would occur because of bypass voiding) serves to make the signal more sensitive to power oscillations.

Furthermore, AREVA stated that the sensitivity of the LPRM detectors is normalized in the determination of the oscillation magnitude. This is true for steady-state operation; however, during regional mode oscillations the heat load to the bypass changes with the flux pulses because of direct moderator heating from prompt radiation. Therefore, the sensitivity at the peak, average, and minimum flux indication conditions varies. Hence, the NRC staff does not find it accurate to state that the sensitivity change is normalized during a regional mode oscillation.

During the oscillation, the peak neutron flux along the contour will increase the heat load to the bypass promptly during a flux pulse. The period of the oscillation guarantees that the delayed neutron and gamma heat load to the bypass is effectively constant; however, the prompt heat load oscillates with the neutron flux. The NRC staff notes the following phenomena as important regarding bypass voiding during conditions susceptible to regional mode oscillation:

- The core power to flow ratio is high, generally resulting in bypass void conditions and/or conditions in the bypass where the liquid is at or near saturation.

- The energy deposited during the neutron flux pulse is promptly deposited in the bypass and water channel liquid.

- The prompt energy release is a large fraction of the direct moderator heat source.

- LPRM indication of the peak flux occurs following the deposition of half of the flux pulse's prompt heat in the bypass.

- LPRM sensitivity decreases with decreasing moderator density.

- The bypass flow around hot channels will react more strongly to flux oscillations than the bypass flow surrounding low-power channels.

Therefore, the NRC staff finds that the LPRM sensitivity during the peak neutron flux will be decreased relative to the sensitivity at the minimum flux. Therefore, the peak flux measurement in the oscillation magnitude determination will be relatively lower than the actual peak neutron flux, and the minimum neutron flux indication will be based on a detector sensitivity much closer to the average sensitivity or the sensitivity of the LPRM before the onset of the instability, if not higher because of reduced voiding. The net result is to decrease the numerator in the normalized oscillation magnitude.

The NRC staff did not perform a rigorous treatment of all phenomena important to characterizing the transient behavior of the bypass. However, Figure 9 in Section 2.8.7.5 of this SE qualitatively illustrates the NRC staff's concerns regarding the effect that prompt energy deposition can have on the sensitivity of the OPRM when the void fraction is transiently varying during potential oscillations.

Significant physical phenomena, including the following, would serve to damp any oscillations in bypass void and hence LPRM sensitivity:

- thermal conduction heat transfer to the bypass below the point of saturation
- delayed direct heat
- reactivity feedback from prompt void formation
- flow feedback from increased buoyancy during void formation
- radial bypass cross-flow
- downward peaked power shapes during regional mode oscillations

The heat deposited in the fluid below the LPRM level D detectors would serve to damp any oscillations in void, considering the applicable phase lag. Furthermore, prompt void formation would serve to damp the initial flux oscillation, and the increased flow caused by voiding would likely sweep the voids with a minimal phase lag above the LPRM level D detectors.

Without additional technical evaluation of all these phenomena in an integrated systems analysis, the NRC staff cannot reach a conclusion regarding the adequacy of LTS Option III to readily detect and suppress oscillations for EPU conditions. However, to address the staff's concerns, the licensee has agreed to apply a penalty to account for this phenomena (see License Condition 3.4.3.1 in Section 3.4.3).

The licensee's LTS Option III DSS is based on a comparison of the peak to average signal. The licensee proposed to determine the change in LPRM sensitivity as a result of the maximum bypass void fraction expected during a dual RPT along the MELLLA line (see Section 2.8.7.5.2). This represents the highest bypass void fraction. The penalty in instrument sensitivity as determined by an approved lattice physics code is then applied to the peak signal to determine an equivalent OPRM signal to initiate a suppression for the same actual oscillation. The NRC staff finds that the licensee's approach is sufficiently conservative because it will assign a penalty (based on the maximum void fraction) to the signal, which would bound, in any case, the magnitude of the oscillation in void fraction occurring promptly with the neutron flux (see Section 2.8.7.5.2). Therefore, the NRC staff finds that the penalty is conservative and is acceptable to ensure adequate performance of the LTS Option III DSS.

Since no safety analyses credit the flow-biased APRM scram signal, the NRC staff did not review the effect of bypass voiding at the LPRM level D detectors on the APRM scram.

2.8.7.2.4 [[ ]] Void-Quality Correlation

The [[ ]] correlation is an historical model that relates the flow quality, which can be directly calculated, to the void fraction. This is also referred to as a slip relationship because the mass flow rate and velocities are related by the void fraction.

There are several areas of uncertainty in applying the [[ ]] void-quality correlation to new fuel designs at high void fraction. The correlation is based on a two-fluid semiempirical bubble rise model. Therefore, uncertainty may be introduced to the calculation as a result of inadequately accounting for the effects of entrained liquid droplets in the vapor core for high void fractions, where the liquid droplets represent an increasingly large fraction of the liquid flow.

As the void reactivity coefficient is a strong function of the void fraction (increasing in magnitude with increasing void fraction), and given the specific concerns regarding the void-quality correlation and concerns regarding the efficacy of steady-state nodal diffusion codes to output reliable nuclear data for use in downstream transient analysis codes where void fractions may exceed 90 percent locally, the NRC staff has reviewed the application of the [[ ]] correlation to perform steady-state predictions of the nodal void fraction.

The efficacy in predicting the nodal void fraction is of particular importance in determining safety system performance during AOOs where there is a reduction in the forced recirculation flow, as would occur for a dual RPT. Under these conditions, the core flow is reduced much more rapidly than the reactor power and high void fractions are expected.

Since the semiempirical [[ ]] correlation formulation is not representative of the three field flow phenomena for annular flow regimes, the NRC staff does not find that extension of this correlation is valid above its qualification database. Furthermore, the NRC staff finds that the database must be representative of the fuel bundle geometry to support the application of the correlation to high void fractions. The prediction of neutronic parameters under reduced recirculation flow AOO conditions pertains to demonstrating adequate compliance with GDC 10 and GDC 12.

The test data supporting the application of the [[ ]] correlation for the SSES EPU application consist of void fraction measurements performed during critical power testing of the ATRIUM-10 fuel bundle. The tests were performed in late 1999 at the KATHY test facility using collimated gamma measurements (Reference 49).

The full-scale tests were performed with qualities extending to approximately 35 percent (34.3 percent) and flow rates as low as 2.6 pounds mass per second (lbm/s), which is well below the predicted hot bundle flow rate under natural circulation conditions. Table 2.8.7.5.b summarizes the tests that were performed to verify the [[ ]] correlation for the ATRIUM-10 bundle.

The void fraction was measured using a traversing gamma instrument. The instrument was properly calibrated at 100 percent and 0 percent void fraction, allowing for the accurate measurement of the water content in the bundle, including the water film around the electrically heated pins. The heated pins are hollow, allowing for the transmission of the gamma beam through these elements in the bundle. Proper calibration of the instrument accounts for the attenuation and allows accurate prediction of the water content laterally across the bundle. Section 2.8.7.5.1 of this SE describes the experimental setup.

The NRC staff has reviewed the ATRIUM-10 void fraction test data and corresponding performance of the [[ ]] correlation to reproduce the measurements. Figure 10 of Section 2.8.7.5 of this SE (from Reference 53), provides the data comparison. The NRC staff notes that the data indicate a consistent bias at low void fraction where the correlation slightly overpredicts the void fraction in the range from 10 to 40 percent. The correlation consistently underpredicts the void fraction in the range between 50 and 80 percent void fraction. The calculated and measured void fractions, however, agree within the uncertainty band for ATRIUM-10 fuel for the entire range of measurement data, which extends to 90 percent void fraction.

The NRC staff finds that the bias is indicative of a correlation based on a semiempirical bubble rise model. At the higher void fractions, increased biases are expected as the effects of interfacial shear along the liquid film drive the vapor slip, and liquid water droplets in the annular core contribute to the total liquid mass flow rate. At the lower void fractions, effects such as subcooled boiling are not fully captured in the formulation of the correlation. Therefore, small divergences are expected when the flow regime is not slug.

The void fraction is very insensitive to quality above 35 percent. The enthalpy increase in the fluid required to achieve higher void fractions would likely also result in dryout conditions. The NRC staff, however, finds that the experimental ATRIUM-10 critical power test data form a valid basis for the application of the [[ ]] correlation under steady-state conditions up to a maximum void fraction of 90 percent. The maximum void fraction predicted for steady-state conditions for the SSES EPU core is less than 90 percent; therefore, the application is acceptable.

The ATRIUM-10 tests confirm that the predicted void fraction is within the established uncertainty range based on previous qualifications; however, this test confirms the application based on the specific ATRIUM-10 geometry. The NRC staff finds that application of the correlation below 90 percent void fraction will not introduce additional error in the predicted nodal or pin powers.

The NRC staff reviewed the application of the [[ ]] correlation above 90 percent and for transient conditions in Section 2.8.7.3.3.

2.8.7.3 Uncertainty Assessment

The NRC staff reviewed the applicability of the uncertainty parameters used in the determination of relevant safety and operating limits based on neutronic methodology efficacy. These are related to the ability to accurately predict the core power distribution both on radial and axial levels, as well as at the nodal, bundle, and pin level.

2.8.7.3.1 Radial Power Distribution

The radial power distribution uncertainty is established based on gamma scans. The radial power distribution calculational efficacy must be determined as bundle powers are established during operation based on a combination of the nuclear core simulation software, LPRM indications, and periodic TIP measurements.

During normal operation, it is not possible to directly measure the power of a particular fuel bundle. The bundle powers may be determined based on the local TIP measurement with a calculation of the radial distribution of the power around the TIP string. For the AREVA neutronic methods, axial elevation bundle gamma scans were performed during the ATRIUM-10 gamma scan campaign. The bundle scans were performed at the axial height of the LPRM instruments. The scans indicate that the neutronic method accurately predicted the distribution of bundle power around the instrument. This is evidenced by the pinwise gamma scans performed at these axial levels. In general, the pinwise standard deviations decrease with axial height.

At greater axial heights, the void fraction increases, resulting in greater Fermi ages and thereby tighter core neutronic coupling. The slight trend in pin power uncertainty in height is attributed to less challenging calculation of the four bundle power distribution. For the pin measurements performed, the maximum pinwise errors were relatively small—the maximum pin power error for the ATRIUM-10 bundle (B91427 in EMF-2158(P)(A)) was [[ ]] for an edge rod at the highest axial elevation. Generally, the ATRIUM-10 and 9x9 bundle scans performed during the KWU-S EOC 13 campaign indicate smaller errors than the campaigns for Quad Cities Unit 1 EOC 2 and EOC 3.

The determination of the radial distribution at these locations is particularly challenging for a nodal neutronic methodology based on the inclusion of an entire bundle of MOX fuel. The presence of large quantities of plutonium early in cycle exposure results in spectrum hardening locally, but it also creates a cascading spectral impact on the neighboring bundles based on the preferential leakage of epithermal neutrons and the prompt neutron yield spectrum for plutonium. The specific MICROBURN-B2 slowing down power correction accurately captures the cross-bundle spectral interaction, making MICROBURN-B2 uniquely adapted to calculate radial bundle and radial pin power distributions for hard spectrum exposure.

Furthermore, the KWU-S gamma scan campaign qualification indicates a combined pin power uncertainty, accounting for four bundle distribution, of [[ ]]. This is substantially similar to the historically determined Quad Cities value of [[ ]] assumed in the SL analysis.

Based on the available gamma scan data, the NRC staff agrees that pin and bundle power uncertainties are not expected to increase by more than [[ ]] of the established values for the somewhat harder spectral conditions present in the SSES EPU core.

The licensee performed a sensitivity analysis whereby the pin power uncertainty was increased by [[ ]]. Based on the limited KWU-S EOC13 gamma scans, the NRC staff finds that the uncertainties are unlikely to increase by more than [[ ]] when the codes are applied to the spectral conditions for the SSES EPU core conditions when compared with slightly softer spectral conditions present in GUN-B. The result of increasing these uncertainties was propagated through the SLMCPR methodology and found to contribute on the order of 0.001 to the SLMCPR. This is below the threshold of importance in the SL. The NRC staff, however, finds that when combined without uncertainties in power distribution, the result may be a combined effect above the significance threshold. Therefore, the staff finds that the adjusted uncertainties in local power should be used to determine the cycle-specific SLMCPR until relevant gamma scan data justifies the use of a smaller quantity.

In consideration of the SSES EPU core, the NRC staff finds that the calculational efficacy of the neutronic methods to determine the distribution of four bundle power surrounding instrument strings will be driven by the robustness of the codes' ability to model cross-bundle leakage and spectral interaction. The licensee addressed the NRC staff concerns regarding extension of the methodology by conservatively assessing the bundle power distribution uncertainty that is input in the SLMCPR methodology.

The bundle power uncertainty that is assumed for the SLMCPR determination is calculated assuming that the cross-bundle correlation parameters are [[ ]], thereby increasing the bundle power uncertainty. The NRC staff finds that the licensee applied this conservatism on the appropriate calculational model to address the NRC staff concerns regarding hard spectrum exposure effects on bundle power distribution. Furthermore, the information presented regarding the limited gamma scans performed at KWU-S EOC 13 confirm the conservatism in the licensee's approach based on excellent agreement of the calculations and measurements for a particularly challenging gamma scan campaign.

The increased bundle power uncertainty of [[ ]], when combined with the LPRM failures, TIP out of service, and LPRM calibration interval uncertainties, results in an increased radial power distribution uncertainty of [[ ]]. The subsequent change in the SLMCPR associated with this increase in bundle power uncertainty is [[ ]] for the same number of rods subject to boiling transition. This radial power distribution uncertainty is further combined with the local power distribution uncertainty, which was increased [[ ]].

Therefore, the conservative reduction in the cross-bundle spectral interaction correlation parameters adequately addresses any uncertainties attributable to bundle power determination under harder spectrum exposure and is acceptable for application to the SSES EPU core conditions.

2.8.7.3.2 Axial Power Distribution

The KWU-S gamma scan campaign included full pinwise axial gamma scans of selected fuel pins. These pins were selected based on specific consideration of the challenges in modeling their performance in the Cycle 13 GUN-B reactor core. These scans included part-length rods, MOX rods, and gadolinia-loaded rods. The ATRIUM-10 test bundle was scanned after one cycle of exposure. After one cycle, the gadolinia is not fully depleted and the axial power profile is a strong function of the depletion history for the gadolinia pins in particular.

While the pinwise gamma scans at the axial heights provide direct evidence of the robustness of the pin power reconstruction and four bundle power distribution models, the axial gamma scans demonstrate the capabilities of the code to track the depletion of gadolinia.

The gamma scan campaign was performed at a point in exposure where the results are most relevant to determining the uncertainty associated with nodal depletion under conditions indicative of EPU operation. The axial scans performed show that the uncertainty in the pinwise axial distribution remains within those values previously established by the Quad Cities gamma scan campaigns.

While the uncertainties that are propagated through the uncertainty analyses for safety and operational limits are based on the historical values, the qualification in EMF-2158(P)(A) provides an acceptable technical basis to determine that the uncertainty values are (1) applicable to the ATRIUM-10 specific geometry, (2) insensitive to the plutonium content, both in the bundle of interest as well as neighboring bundles, (3) insensitive to the gadolinia loading (the ATRIUM-10 bundle was loaded with 11 gadolinia rods), and (4) unaffected by operation at EPU conditions in the GUN-B reactor.

The NRC staff reviewed the associated methodology description presented in EMF-1833(P). The specific models that contribute to the robustness of the AREVA methods include the (1) slowing down power correction for cross-bundle spectral interaction, (2) the method of characteristics solution that preserves gadolinia pin radial geometry at the lattice level, (3) the fine energy mesh collapsing of cross-sections and microscopic tracking that allows for accurate tracking of principle nuclides that are highly sensitive to the neutron spectrum, particularly plutonium isotopes, and (4) the pin power reconstruction model that accounts for both lattice distributions and gross radial tilts based on the lattice information and boundary conditions. In essence, the NRC staff finds that the exercise of these models for the Quad Cities gamma scan campaigns may not have been required to achieve the same degree of agreement, but their inclusion has been both qualified through recent gamma scan efforts and justified based on a rigorous treatment of the sublattice neutronic effects.

In Section 2.8.7.5.3 of this SE, the NRC staff has included selected axial gamma scans. These include specific ATRIUM-10 gamma scans for a gadolinia rod, a part-length rod, and the peak power rod (adjacent to the water channel). These rod gamma scans indicate excellent agreement. The NRC staff also considered a challenging rod in the MOX bundle. The NRC staff included the pin axial gamma scan data for a high-power MOX fuel pin. The MOX pin is sensitive to the sublattice spectrum collapsing and hence the modeling of the axial variation in neutron flux spectrum. The results indicate excellent agreement between the calculated and measured axial pin powers.

The NRC staff therefore finds that the demonstration of the code's performance for the KWU-S gamma scan provides an adequate and acceptable basis for the bundle power uncertainty adjustment to account for extension of the methods to SSES EPU core conditions.

2.8.7.3.3 <u>Consideration of the Void Uncertainty</u>

In general, uncertainty in the void correlation is not directly propagated to determine SLs because the interaction mechanisms between flow, void fraction, and power cannot be separately and directly measured in an integral sense. Separate qualification of the void-quality correlation with acceptable power predictions based on plant TIP measurements and neutronic model qualification based on pinwise gamma scans forms a suite of validations that demonstrate the overall modeling capability.

The most direct measurement of the core power distribution comes from TIP measurements at various reactor facilities during operation. The TIP measurements, however, serve as an integral assessment of both the neutronic aspects of the model as well as the thermal-hydraulic aspects of the model. TIP measurements alone do not provide an acceptable or adequate basis in the determination of uncertainties because of the strong feedback between the void conditions in the core and the local power distribution.

Therefore, a complete qualification requires separate determination of the neutronic uncertainties and the void fraction uncertainties. The purpose for separately qualifying these models is to give a degree of assurance that each aspect of the overall modeling capability provides acceptable results without coupling. In the case where a SL uncertainty assessment rests solely on qualification against full-scale plant data, there is not assurance that the feedback is either masking or compounding errors in both of the neutronic and thermal-hydraulic models; therefore, operation outside of those specific scenarios measured in the plant cannot be predicted with a high degree of confidence.

In this specific case, full-scale testing was performed to validate the void-quality correlation at the KATHY test facility. The coefficients of the [[ ]] correlation were not adjusted based on the data gathered in the test; rather, the test served as a demonstration of the applicability of the correlation to the conditions expected during the operation of the ATRIUM-10 test bundle up to the point of dryout. These tests were performed without consideration of neutronic feedback and therefore serve as a separate effects qualification of a key model in the thermal-hydraulic solver of the nuclear core simulation software.

The NRC staff has noted that the semiempirical nature of the correlation does not allow extension of the correlation above those conditions specifically measured in full-scale tests. However, with any slip-based void-quality correlation, the void fraction becomes insensitive to the flow quality. Therefore, dramatic changes in the quality are necessary to achieve modest changes in void fraction for high void fractions. Under operating conditions, the core power affects the flow quality, which affects the nodal void fraction, which, in turn, affects the core power via neutronic feedback mechanisms. The full-scale testing, therefore, is not a measure of the influence that the void-quality correlation will have on actual plant uncertainties, and the feedback mechanism is sufficiently complex that the propagation of a particular uncertainty into bundle power would not be straightforward.

Therefore, a complete assessment of the impact of uncertainties in the correlation must separately consider the neutronic methodology independent of the thermal-hydraulic conditions. This assessment is generally in the form of comparisons of the neutronic methods to sophisticated transport calculations, critical experiments, and high-order neutronic core methods. ANP-2638(P), Revision 0, “Applicability of AREVA NP BWR Methods to Extended Power Uprate Conditions,” issued July 2007 (Reference 53), contains comparisons between CASMO-4 and the Monte Carlo N–Particle transport code with good agreement. EMF-2158(P)(A) includes additional qualification benchmarks. The uncertainties established based on code comparisons and critical assembly evaluations, much like uncertainties in the void fraction, are not directly propagated through SL analyses either. The dual separate effects qualification demonstrates that, independently, these two aspects of the methodology do not contribute to a consistent bias, and therefore there is a reasonable assurance that the coupling of the methods will not mask uncertainties in integral performance assessments.

TIP measurements, bundle gamma scans, and pinwise gamma scans provide the remaining necessary element in the determination of the uncertainty. The TIP measurements provide a comparison of predicted and measured axial power distribution. Given the strong coupling between the neutron flux and the void fraction, and given that each model has been separately qualified, there is reasonable assurance that accurate predictions indicate accurate modeling of each component in the nuclear feedback and overall power distribution solution.

For a given measured axial power distribution, the quality distribution can essentially be calculated with a high degree of accuracy based on fluid thermodynamic properties. A systemic, unquantified error in the void fraction would perturb the local power distribution. A significant local power perturbation would be necessary to achieve a corresponding quality perturbation for the solution to indicate a significantly different void fraction based on the nature of slip correlations at high void fractions.

However, the NRC staff notes that under certain transient conditions the thermal-hydraulic conditions of the core may drastically change, resulting in increased void fractions, reduced flow, or dramatic power peaking. For these scenarios, the [[ ]] correlation is deficient based on inherent assumptions regarding the nature of the fluid behavior. While the NRC staff notes that 100 percent quality and 100 percent void fraction will correspond in the formulation, three field and annular flow phenomena, which may depend on bundle geometry and heat flux, drive the exact trends in void and quality above the qualification and this intersection.

The NRC staff considered the use of the correlation to established steady-state input for downstream transient evaluations. The NRC staff notes that a separate correlation is used for transient evaluations. In the case where an AOO is simulated, the correlation extends to void fractions above the steady-state void fraction and considers a range of conditions up to the point of dryout. For the KATHY test, this extends to [[ ]] void fraction. For the assessment of performance under transient conditions terminating in a scram, the NRC staff finds that the models do the following:

- The models will predict the onset of dryout before exceeding the qualification data set for the void fraction correlation. While the code may predict unreliable void fractions that are higher in a postdryout scenario, this does not impact the code's ability to predict cladding damage.

- The models will calculate transient variation in void fraction based on the transient core power and hence thermal energy absorbed by the coolant. For void fractions of [[ ]], the void-quality correlation derivative (change in void fraction with enthalpy rise) is essentially independent of slip (see Figures 12 and 13 in Section 2.8.7.5 of this SE). For the high void fraction case, the transient predicted change in void fraction corresponding to a change in the thermal energy deposition will be accurately predicted regardless of any deficiency in the correlation.

Therefore, the NRC staff finds that adequately qualifying the void-quality correlation up to [[ ]] ensures that transient analyses terminated by scram provide accurate determination of the number of rods in dryout and the proper void reactivity feedback.

The NRC staff requested that the licensee evaluate the sensitivity of the core operating limits to biases in the void-quality correlation. To address the NRC staff concerns, the licensee performed a sensitivity analysis by [[

]].

[[

]]. Therefore, the NRC staff agrees that the analysis captures the effect of consistent void bias on the depletion during normal operation and its subsequent impact on the transient analysis.

The limiting transient events were analyzed at the new EOC conditions [[ ]]; these included load rejection with no bypass, FW controller failure, and turbine trip without bypass. The results indicated [[

]].

Therefore, the NRC staff finds that [[ ]] void-quality correlation uncertainties do not require separate propagation through the SL determination given that the test data are within the bias observed for the [[ ]] verification against ATRIUM-10 tests.

Furthermore, the NRC staff has reviewed the trends in void fraction with increasing quality. The NRC staff finds that the correlation application for transients above [[ ]] void fraction is acceptable, as is application of the correlation to steady-state conditions without dryout. The NRC staff finds that the current uncertainty analysis sufficiently captures the relevant uncertainties in power distribution and the void-quality relationship. Therefore, the NRC staff agrees that no other explicit limit on void fraction is required to ensure adequacy of the current uncertainty parameters and transient analysis results, since geometry specific validation was performed up to [[ ]] void fraction.

2.8.7.4 Summary of Evaluation

The NRC staff has found that extensive qualification of the neutronic methods and constitutive models provides an adequate technical basis for the extension of the AREVA nuclear design methods to ATRIUM-10 fuel under the EPU conditions present at SSES 1 and 2.

The NRC staff reviewed the nuclear design and instrumentation in regards to GDC 12 and 13 and found that the presence of bypass voids around the LPRM level D detectors affect the instrument sensitivity. The NRC staff finds that the conservatism in the OPRM setpoint setdown methodology adequately ensures compliance with GDC 12 and 13.

The NRC staff has determined that the following license conditions should be imposed with respect to the neutronics methods under EPU conditions for SSES 1 and 2:

A. An OPRM amplitude setpoint penalty will be applied to account for a reduction in thermal neutrons around the LPRM detectors caused by transients that increase voiding. This penalty will reduce the OPRM scram setpoint according to the methodology described in Response No. 3 of PPL letter, PLA-6306, dated November 30, 2007. This penalty will be applied until NRC evaluation determines that a penalty to account for this phenomenon is not warranted.

B. For SSES SLMCPR analyses, a conservatively adjusted pin power distribution uncertainty and bundle power correlation coefficient will be applied as stated in Response No. 4 of PPL letter, PLA-6306, dated November 30, 2007, when performing the analyses in accordance with ANF-524(P)(A), “Advanced Nuclear Fuels Corporation Critical Power Methodology for Boiling Water Reactors,” using the uncertainty parameters associated with EMF-2158(P)(A) “Siemens Power Corporation Methodology for Boiling Water Reactors: Evaluation and Validation of CASMO-4/MICROBURN-B2.”

2.8.7.5 Supplemental Information - AREVA Nuclear Design Methods

2.8.7.5.1 Void Quality Correlation Validation and Testing

PPL provided the following additional information by letter dated November 30, 2007 (Reference 55) regarding void fraction measurement and the void quality correlation:

> Void Quality Correlation
>
> The void correlation used for the SSES CPPU cycle design ([[ ]]) has been validated against measured ATRIUM-10 void fractions up to void fractions of [[ ]]. The comparison shows that the standard deviation between calculated and measured values is [[ ]]. The question has been raised with respect to the impact of void fraction uncertainties for higher void fractions on MCPR.
>
> Inaccuracies in the AREVA void-quality relationship directly contribute to the assembly power uncertainty that is used in computing the cycle-specific SLMCPR. Void reactivity is a strong feedback mechanism in BWRs, so that deviations in the void fraction are exhibited as deviations between the calculated and measured TIP distributions. As the void deviations increase, the effective radial power uncertainty would also increase. From this perspective, the AREVA licensing limits already incorporate the void correlation uncertainties.

To explore the question further, a sensitivity study was performed to assess the impact on licensing limits of biasing the current correlation towards the extreme of the ATRIUM-10 correlation data. [[

[[

]]

[[

]].

[[

]]

Summary

First, the assembly radial power uncertainty already includes uncertainties in the void correlation. Second, no significant increase in uncertainties will occur at void fractions above those measured in the KATHY facility. Finally, a sensitivity calculation was performed to assess the impact of introducing a bias in the void correlation [[ ]]; the results demonstrated that the OLMCPR did not change.

[[

[[

]]

[[

]]

Void Fraction Measurement

[[

]].

[[

]]

[[

]]

2.8.7.5.2 Bypass Voiding and Long-Term Stability Solution Performance

PPL provided the following additional information by letter dated November 30, 2007 (Reference 55) regarding the impact of bypass voiding on the OPRM amplitude setpoint:

Bypass Voiding

The OPRM system consists of four OPRM trip channels. Each trip channel in the SSES OPRM system is divided into 30 OPRM cells; the signal for each cell consists of the sum of four LPRMs in a localized region of the core. A trip setpoint specifies the normalized amplitude (peak/average cell signal) at which each LPRM cell will generate a cell trip. A reactor scram is generated when one OPRM cell trips in any two OPRM channels (two-out-of-four logic).

A dual RPT starting on the MELLLA boundary will produce the highest increase in bypass voiding. The SSES TSs require an immediate, manual reactor scram upon entry into natural circulation. Thus, the natural circulation condition would be present only a short time—operation at natural circulation is not permitted at SSES.

A dual RPT would result in a small increase in voiding near the top of the core bypass region. Thus, the signal of the LPRMs near the upper LPRMs (D-Level LPRMs) may be decreased because of the reduction in thermal neutrons around the detectors caused by the presence of the increased voiding.

The reduced signal from the upper LPRMs would affect the signal provided to the OPRM system. [[

]]

[[

]], PPL will conservatively assume that only the oscillatory part of the OPRM cell signal (numerator of the normalized amplitude signal) is affected to determine a conservative trip setpoint penalty. This penalty will be determined as described below.

The highest amount of upper bypass voiding occurs at the highest core power to core flow ratio. The highest core power to core flow ratio occurs within the operating domain on the MELLLA boundary at natural circulation conditions. This operating condition will be used to determine the maximum expected voiding in the top of the bypass. Once the amount of bypass voiding is determined, the effect of the voiding on the LPRM signal will be determined by lattice physics calculations that model the bypass voiding around the detector. The calculated reduction in the LPRM signal will then be used to determine an OPRM amplitude setpoint penalty.

Since the OPRM cells compare a normalized oscillation amplitude setpoint to a normalized OPRM signal, the conservative OPRM amplitude setpoint penalty would be applied to the portion of the setpoint above 1. For example, if the OPRM amplitude setpoint is 1.15 and the OPRM penalty is 5 percent, the OPRM setpoint penalty would be 0.0075, resulting in an effective OPRM amplitude setpoint of 1.14.

Bypass Voiding Effects on Detector Sensitivity

The following AREVA supplemental information was submitted per Reference 57:

An OPRM signal is a combination of signals from several LPRM detectors located at different elevations. The sensitivity of the upper elevation D-level is reduced in case of boiling in the bypass because of the higher weighting of the bypass neutron moderation effectiveness at the detector location. The effect of the reduced sensitivity of the D-level detectors [[
]].

[[

]].

The effect of the reduced sensitivity of the D-level detectors is shown to be [[

]].

The effect of the bypass boiling on detector sensitivity does not warrant a special consideration because of implementation of the enhancements to the existing Option III or for application to extended flow operating domains such as MELLLA+. This is the case because the Period Based Detection Algorithm (PBDA) oerating domain is limited by scram upon entering the single channel exclusion region; thus, the extent of bypass boiling does not change in any significant way because of the introduction of the single channel scram region.

2.8.7.5.3 Gamma Scan Measurements for ATRIUM-10 Fuel

KWU-S EOC 13 Gamma Scan Data

As described in Reference 54, gamma scan measurements were performed on an ATRIUM-10 bundle at EOC 13 at the GUN-B reactor during the 1998 outage. GUN-B is a 3840 MWt reactor with 784 fuel bundles arranged in a C lattice. The ATRIUM-10 bundle that was selected for the scan was exposed at a high power density and had achieved a bundle exposure near the peak reactivity point following one cycle's worth of burnable poison depletion.

The scan includes half of the pins in the assembly at four discrete axial locations and a continuous axial scan for five of the pins, including one gadolinia-poisoned pin and one part-length rod. The NRC staff examined the results presented for three pins of interest—the part-length pin, the gadolinia pin, and the peak power pin. The peak power pin is a highly enriched pin adjacent to the water channel. The gadolinia pin, though depleted in gadolinia, has a pin power peaking factor of roughly 0.94, whereas the peak power pin radial peaking factor ranges between 1.08 and 1.12 axially for the scanned ATRIUM-10 lattices.

Figures [5] through [7] provide the axial gamma scan results. The part-length rod is enriched to 2.9 percent, and the gadolinia rod is enriched to 3.9 percent with a gadolinia concentration of 2.5 percent. The results show very good agreement regardless of pin power level, gadolinia content, or pin length. The particularly good agreement in the gadolinia pin axial power shape given the range of axial exposure (10–15 gigawatt day per ton (GWD/T)) indicates the robustness of the MICROBURN-B2 gadolinia depletion modeling.

[[

]]

[[

]]

[[

]]

[[

]]

Gamma Scan Impact on Minimum Critical Power Ratio Safety Limit Calculations

PPL submitted additional information by letter dated November 30, 2007 (Reference 55) regarding the gamma scan data and the methodology associated with calculating the SLMCPR.

> The available AREVA gamma scan data will be used to determine the impacts on the calculated power distribution uncertainties. The power distribution uncertainties are inputs to the SLMCPR calculation. Both pin and bundle power distribution uncertainties are addressed as described below.
>
> Gamma Scan Impact on Bundle Power Distribution Uncertainty
>
> Bundle gamma scan data are not used directly to define the calculated bundle power distribution uncertainty. Gamma scan data are used to define the correlation coefficients as described in EMF-2158(P)(A). Both TIP uncertainties and these correlation coefficients are used to calculate the bundle power distribution uncertainty. The correlation coefficient is determined from comparison of the calculated power distribution to available bundle gamma scan data.
>
> The TIPs directly measure the local neutron flux from the surrounding four fuel assemblies. Thus, the calculated bundle power distribution uncertainty will be closely related to the calculated TIP uncertainty. However, the bundle powers in the assemblies surrounding a TIP are not independent because, if a bundle is higher in power, neutronic feedback will increase the power in the nearby assemblies, thus producing a positive correlation between nearby bundles. The gamma scan data provide the means to determine this correlation according to the EMF-2158(P)(A) methodology. A smaller correlation coefficient implies that there is less correlation between nearby bundle powers; thus, there would be a larger bundle power distribution uncertainty.
>
> Existing Gamma Scan Results
>
> The average correlation coefficient as defined in EMF-2158(P)(A) was calculated to be [[ ]]. The calculated TIP uncertainty was determined to be [[ ]] in EMF-2158(P)(A). Combining the calculated TIP uncertainty and the correlation coefficient results in a calculated bundle power distribution uncertainty of [[ ]].
>
> [[
>
>]]
>
> A sensitivity calculation was performed to evaluate the change in the correlation coefficient for the SSES CPPU design. For the CPPU cycles, the calculated bundle power distribution uncertainty is combined with other uncertainties to produce the

measured radial power uncertainty with assumed LPRM failures, number of TIPs out of service, and a specified LPRM calibration interval. [[

]]

Until further gamma scan data are available, the conservatively adjusted correlation coefficient will be used for the SSES CPPU to calculate an adjusted bundle power distribution uncertainty as discussed above. The MCPR SL calculation for the SSES CPPU licensing analysis will use the adjusted bundle power distribution uncertainty.

Gamma Scan Impact on Pin Power Distribution Uncertainty

Pin-by-pin gamma scan data are used to determine the local power uncertainty. The pin gamma scan data from Quad Cities was taken at seven axial levels and resulted in a pin power distribution uncertainty of [[ ]]. Additional pin gamma scans were taken by KWU at four axial levels and included two 9X9 uranium dioxide, one 9X9 MOX, and one ATRIUM-10 uranium dioxide assemblies. The local power uncertainty from the KWU data was [[ ]], which is very consistent with the Quad Cities data. The consistency of these very different sets of data indicates that additional gamma scan data would not change the uncertainty significantly. Furthermore, there is no trend in the standard deviations as a function of axial level, indicating that the local power uncertainty is not void fraction dependent.

A sensitivity study was performed to evaluate the impact of local power uncertainty on the calculated SLMCPR. [[

]]

The pin power distribution uncertainty will be increased by 50 percent for the SSES SLMCPR analyses for the CPPU. This is consistent with the treatment of the gamma scan contribution to the bundle power distribution uncertainty.

Conclusion

The available AREVA gamma scan data will be used to determine the impacts on the calculated power distribution uncertainties. The power distribution uncertainties are inputs to the SLMCPR calculation. Adjusted pin and bundle power distribution uncertainties will be used for the SSES SLMCPR analyses for the CPPU [See Table 2.8.7.5.a below].

Table 2.8.7.5.a SLMCPR Uncertainties

Table A.1 Uncertainties Used in the CPPU and SSES Uprate SLMCPR		
Parameter	Submitted CPU Analysis (from PLA-6076)	Future CPPU Analysis (Proposed)
Reactor System Uncertainties		
FW Flow Rate	1.76%	1.76%
FW Temperature	0.76%	0.76%
Core Pressure	0.5%	0.5%
Total Core Flow Rate	2.5%	2.5%
Fuel-Related Uncertainties		
Radial Power	[[ ]]	[[ ]]
Assembly Flow Rate	[[ ]]	[[ ]]
Local Power	[[ ]]	[[ ]]
SPCB Additive Constant	[[ ]] [[ ]]	[[ ]] [[ ]]

* [[
]]

2.8.7.5.4 Additional Figures and Tables

[[

]]

[[

]]

[[

]]

[[

]]

[[

]]

[[

]]

2.9 Source Terms and Radiological Consequences Analyses

Regulatory Evaluation

This section addresses the impact of the proposed EPU on DBA radiological consequence analyses as well as previously analyzed source terms used in radwaste management systems analyses. The NRC staff based its acceptance of the source terms used for input into radwaste management systems analyses on the regulatory requirements in 10 CFR Part 20, "Standards for Protection Against Radiation"; Appendix I to 10 CFR Part 50; and GDC 60 in Appendix A to 10 CFR Part 50. The NRC staff based its acceptance of the DBA radiological consequence analyses on the accident dose criteria in 10 CFR 50.67.

Except where the licensee proposed a suitable alternative, the NRC staff used the regulatory guidance provided in the following documents in performing this review:

- RG 1.183
- SRP Section 11.1
- SRP Section 15.0.1

The NRC staff considered relevant information in the UFSAR, TSs, PUSAR, and EPU supplemental environmental report for SSES Units 1 and 2. The NRC staff reviewed the impact of the power uprate on the areas included in Matrix 9 of RS-001.

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 SSES Unit 1 and 2 UFSAR related to LWMSs and GWMSs. The NRC's acceptance criteria for source terms are based on (1) 10 CFR Part 20, insofar as it establishes requirements for radioactivity in liquid and gaseous effluents released to unrestricted areas, (2) Appendix I to 10 CFR Part 50, insofar as it establishes numerical guides for design objectives and LCOs to meet the ALARA criterion, and (3) GDC 60, insofar as it requires that the plant design include the means to control the release of radioactive effluents. SRP Section 11.1 contains specific review criteria.

Technical Evaluation

The core isotopic inventory is a function of the core power level, while the reactor coolant isotopic activity concentration is a function of the core power level, the migration of radionuclides from the fuel, the presence of corrosion products or contaminants, radioactive decay, and the removal of radioactive material by coolant purification systems. The licensee previously submitted a separate LAR to implement an AST in accordance with 10 CFR 50.67, which the NRC approved in a letter dated January 31, 2007, as Amendment No. 239 to Facility

Operating License No. NPF-14 and Amendment No. 216 to Facility Operating License No. NPF-22 for SSES Units 1 and 2. The analyses supporting the AST amendments included fission product inventories based on EPU conditions for a full core of ATRIUM-10 fuel.

In Section 8.4 of the PUSAR, the licensee discussed the impact of the EPU on the radiation sources in the reactor coolant. Radiation sources in the reactor coolant include activation products, activated corrosion products, and fission products. During reactor operation, some stable isotopes in the coolant passing through the core become radioactive (activated) as a result of nuclear reactions. For example, the nonradioactive isotope oxygen-16 is activated to become radioactive nitrogen-16 by a neutron-proton reaction as it passes through the neutron-rich core at power. The coolant activation, especially nitrogen-16 activity, is the dominant source in the turbine building and in the lower regions of the drywell. The increase in the activation of the water in the core region is in approximate proportion to the increase in thermal power. The licensee asserted, and the NRC staff agrees, that since the margin in the current SSES Unit 1 and 2 plant design basis for reactor coolant activation concentrations exceeds potential increases resulting from the EPU, no change is required in the activation design-basis reactor coolant concentrations for the EPU.

The reactor coolant contains activated corrosion products, which are the result of metallic materials entering the water and being activated in the reactor region. Under EPU conditions, the FW flow and the activation rate in the reactor increase with power. Although some increase in the development of activated corrosion products may result with EPU, the magnitude is not expected to be significant. The licensee calculated corrosion product activity concentrations based on ANS 18.1-1999 and concluded that the current design basis bounds the results for EPU conditions. The standard method in ANS 18.1-1999 is an equilibrium analysis for determining coolant concentration that is proportional to power, inversely proportional to total water mass, and to a lesser extent inversely proportional to steamflow. The levels of moisture carryover expected at EPU steaming rates are unchanged (≤ 0.1 weight %) and are not expected to result in any added buildup or dose rate consequence as a result of activated corrosion products in the BOP.

Fission products in the reactor coolant are separable into the products in the steam and the products in the reactor water. The activity in the steam consists of noble gases released from the core plus carryover activity from the reactor water. This activity is the noble gas offgas that is included in the plant design. Using the same methodology as in the current licensing-basis analyses, the licensee has determined that the calculated offgas rates for EPU, after 30 minutes decay, are well below the original design basis of 0.10 curies per second. Therefore, the licensee asserted, and the NRC staff agrees, that no change is required in the design basis or TS limit for offgas activity as a result of the EPU.

The fission product activity in the reactor water, like the activity in the steam, results from releases from the fuel rods. The licensee used ANS 18.1 methods to predict the concentration of fission product activity levels in the reactor water for EPU conditions. The licensee determined that the current license thermal power design-basis values bound the resultant concentrations and that the TS limit for reactor water concentrations will not change as a result of the EPU.

The licensee used methodologies in the current SSES Unit 1 and 2 licensing basis and followed the guidelines in SRP Section 11.1 to evaluate the impact of the EPU on the radiation sources in the reactor coolant. Therefore, the NRC staff finds the licensee’s evaluation of the source terms for radwaste systems analyses acceptable.

Conclusion

The NRC staff has reviewed the radioactive source term associated with the proposed EPU and concludes that the proposed parameters and 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, Appendix I to 10 CFR Part 50, 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 performed at the EPU power level that the licensee submitted in support of the SSES Unit 1 and 2 AST license amendment. The radiological consequences analyses reviewed are the LOCA, MSLB, fuel and equipment handling accident, and the CRDA. 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 TEDE. The NRC based its acceptance criteria for radiological consequences analyses using an AST on 10 CFR 50.67. These criteria are 25 rem TEDE at the exclusion area boundary for any 2-hour period following the onset of the postulated fission product release, 25 rem TEDE at the outer boundary of the low-population zone for the duration of the postulated fission product release, and 5 rem TEDE for access and occupancy of the control room for the duration of the postulated fission product release. Regulatory Position 4.4 of RG 1.183 and Table 1 of SRP Section 15.0.1 contain accident-specific criteria for the exclusion area boundary and the low-population zone, supplementing 10 CFR 50.67.

Technical Evaluation

Section 9.2 of the PUSAR discusses the impact of the EPU on the radiological consequences of DBAs. The licensee performed DBA dose analyses at a power level of 4032 MWt, which is 102 percent of the proposed EPU RTP level of 3952 MWt. The licensee submitted these analyses by letter dated October 13, 2005, and requested a license amendment to revise the SSES Unit 1 and 2 licensing basis to support a full-scope implementation of an AST in accordance with 10 CFR 50.67. The NRC staff found the AST DBA dose analyses to be acceptable and issued Amendment No. 239 to Facility Operating License No. NPF-14 and Amendment No. 216 to Facility Operating License No. NPF-22 for SSES Units 1 and 2, respectively.

In support of the AST amendments, the licensee evaluated all significant DBAs currently analyzed for radiological consequences in the SSES Unit 1 and 2 UFSAR. These events are the LOCA, MSLB, fuel and equipment handling accident, and CRDA. In its previous review for the AST amendments, the NRC staff compared the doses estimated by the licensee to the applicable regulatory criteria and found, with reasonable assurance, that the licensee's estimates of the offsite and control room doses will continue to comply with the applicable regulatory criteria. The SE for the AST amendment stated that the NRC staff found that the radiological consequences of DBAs would remain bounding up to an RTP of 3952 MWt. Nothing in the EPU submittal invalidates this previous finding by the NRC staff.

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 ESF systems remain acceptable with respect to the radiological consequences of postulated DBAs since, as set forth above, the calculated TEDE at the exclusion area boundary, at the low-population zone outer boundary, and in the control room meet the acceptance criteria specified in 10 CFR 50.67, as well as applicable acceptance criteria denoted in SRP Section 15.0.1. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to the radiological consequences of DBAs.

2.10 Health Physics

Regulatory Evaluation

The NRC staff conducted its review in this area to ascertain the overall effects the proposed EPU will have on both occupational and public radiation doses and to determine whether the licensee has taken the necessary steps to ensure that any dose increases will be maintained within applicable regulatory limits and ALARA. The NRC staff's review included an evaluation of any increases in radiation sources and their potential effect on plant area dose rates, plant radiation zones, and plant area accessibility. The NRC staff also evaluated the effect on personnel doses needed to access plant vital areas following an accident. The NRC staff considered the effects of the proposed EPU on nitrogen-16 levels in the plant as well as any effects on radiation doses outside the plant and at the site boundary from skyshine. The NRC staff also considered the effects of the proposed EPU on plant effluent levels and any increased radiation doses from those effluents at the site boundary. The NRC based its acceptance criteria for occupational and public radiation doses on 10 CFR Part 20, 10 CFR 50.67, Appendix I to 10 CFR Part 50, and GDC 19. SRP Sections 12.2, 12.3, 12.4, and 12.5 contain specific review criteria, and Item II.B.2 of NUREG-0737, "Clarification of TMI Action Plan Requirements," issued November 1980, and Matrix 10 of RS-001 provide other guidance.

2.10.1 Occupational and Public Radiation Doses

Technical Evaluation

Source Terms

The EPU maximum authorized power level of 3952 MWt is approximately a 13-percent increase from the licensee's CLTP level of 3489 MWt.

During power operation, the radiation sources in the core are directly related to the fission rate. These sources include radiation from the fission process, accumulated fission products, and neutron reactions as a result of fission. The core fission product inventories are based on the assumed fuel irradiation time, which develops equilibrium activities in the fuel, typically 3 years. Most radiologically significant fission products reach equilibrium within a 60-day period. Therefore, for the CPPU, the percent increase in power level is expected to result in a proportional increase in the direct (e.g., reactor fuel) and indirect (e.g., reactor coolant) radiation source terms.

However, because of the physical and chemical properties of the different radioactive materials that are in the reactor coolant and the processes that transport these radioactive materials to components in the plant, several radiation sources outside of the reactor are not expected to change in direct proportion to the increase in reactor power.

The concentration of nonvolatile fission products, actinides, and corrosion and wear products in the reactor coolant is expected to increase proportionally with the power increase. However, the increase in steamflow is expected to result in a small percentage of moisture carryover leading to the movement of these products to steam plant components and equipment, causing increased dose rates in these areas. Although there are increases in dose rates in these steam-affected areas, these expected increases continue to be within the shielding design margins for the condensate, FW, and other affected systems.

The concentration of noble gases and other volatile fission products in the MSL will not change. The increased production rate of these materials in the reactor core is offset by the corresponding increase in steamflow; therefore, the concentration of these materials in the steamline remains constant. Although the EPU will result in an increase in the rate these materials are introduced into the main condenser and offgas systems, these expected increases continue to be within the design margins of the offgas system.

For the short-lived activities, the most significant is nitrogen-16; the decreased transit (and decay) time in the MSL and the increased mass flow of the steam result in a larger increase in these activities in the major turbine building components. An increase in the nitrogen-16 concentration of 6 percent occurs because of a reduction in the time for nitrogen-16 to decay, resulting from the shortened transit time of the steam through the MS and turbine equipment. Nitrogen-16 activity increases from the neutron activation that results from the increased power level of approximately 13 percent. Based on these, the licensee estimated that the post-EPU nitrogen-16 operational dose rates will increase up to 20 percent at some onsite locations because of direct and scattered radiation from MS and turbine equipment at EPU conditions.

Radiation Protection Design Features

<u>Occupational and Onsite Radiation Exposures</u>

The NRC staff has reviewed the licensee’s plan for EPU with respect to its effect on the facility radiation levels and on the radiation sources in the core and coolant. The radiation sources in the core include radiation from the fission process, accumulated fission products, and neutron reactions as a result of neutron activation. The radiation sources in the core are expected to increase in proportion to the increase in power. These sources include radiation directly produced in the fission process from the decay of accumulated fission products and by secondary neutron reactions as a result of fission. However, the existing safety margins of the design-basis sources bound this increase. Since the RV is inaccessible to plant personnel during operation, and because of the design of the shielding and containment surrounding the RV, an increase of approximately 13 percent in the radiation sources in the reactor core will have no effect on occupational worker personnel doses during power operation.

In addition, the radiation shielding provided in the steam-affected areas of the plant is conservatively sized such that the increased source terms discussed above are not expected to significantly increase the dose rates in the normally occupied areas of the plant. Radiation dose rates in steam-affected areas of the plant are estimated to increase by 20 percent. These areas (including the reactor and turbine steam tunnels, moisture separator rooms, turbine rooms, high-and LP heater rooms, condenser rooms, moisture separator drain pump and tank rooms, steam jet air ejector rooms, and hydrogen recombiner rooms) are all currently designated as high-radiation areas, and personnel access to them is restricted and controlled accordingly. The existing radiation zoning design (e.g., the maximum designed dose rates for each area of the plant) for areas outside the steam-affected areas will not change as a result of the increased dose rates associated with this EPU.

During EPU testing, the change in power is expected to impact radiation monitoring of selected plant areas, and an increase of nitrogen-16 activation levels will be conducted. Some of these areas include the normally accessible areas adjacent to steam-affected areas in the turbine building as well as the normally accessible areas in the radwaste and the reactor buildings. Compliance with existing radiation postings will be verified during these surveys.

Operating at approximately a 13-percent higher power level will result in an increased core inventory of radioactive material that is available for release during postulated accident conditions. Item II.B.2 of NUREG-0737 states that the occupational worker dose guidelines of GDC 19 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 (excluding inhalation dose) to personnel should not exceed 5 rem whole body, or its equivalent to any part of the body for the duration of the accident. The licensee previously submitted a LAR to fully implement the AST methodology, which the NRC approved on January 31, 2007, for which the AST worker dose acceptance criterion is no more than 5 rem TEDE. The licensee performed calculations that showed the impact of the AST on NUREG-0737 radiological evaluations that are based on TID-14844 DBA-LOCA releases. The calculations concluded that the current NUREG-0737 radiological evaluations performed with TID-14844 releases are bounding for the DBA-LOCA AST for a reactor power of 4032 MWt. Based on these conservative calculations, the highest calculated postaccident vital area worker TEDE for personnel performing required post-LOCA vital area duties in the plant is less than 4.5 rem TEDE, which is below the dose criterion of GDC 19.

Therefore, following implementation of this EPU, SSES Units 1 and 2 will continue to meet their design basis in terms of radiation shielding, in accordance with the criteria in SRP Section 12.4 and the requirements of GDC 19 and 10 CFR 50.34(f)(2)(vii) detailed in NUREG-0737, Item II.B.2.

Public and Offsite Radiation Exposures

The primary sources of normal offsite doses at SSES Units 1 and 2 are (1) airborne releases, (2) gamma shine from plant turbines, and (3) liquid effluent releases from the radwaste system. As described above, this EPU will increase gaseous effluents from the plant during normal operations by approximately 13 percent. This increase is a minor contribution to the radiation exposure to the public. The nominal annual public dose from plant gaseous effluents for SSES Units 1 and 2 is about 0.771 millirem (mrem). A 13-percent increase in this nominal dose is still well within the 10 mrem per year dose criterion in Appendix I to 10 CFR Part 50 and the 25 mrem per year dose criterion in 40 CFR Part 190, “Environmental Radiation Protection Standards for Nuclear Power Operations.”

This EPU will result in some increased generation of liquid waste. The increased condensate feed flow results in faster loading of the condensate filters and demineralizers. This higher feed flow introduces more impurities in the reactor coolant, resulting in faster loading of the RWCU system filter demineralizers. The condensate filters and RWCU filter demineralizers in both these systems will therefore require more frequent backwashing. The licensee has estimated that these more frequent backwashes as a result of the EPU will increase the volume of liquid waste by 1 percent. This increase is well within the processing capacity of the radwaste system and is not expected to noticeably increase the liquid effluents released from the plant. Therefore, this small increase will have a negligible impact on occupational or public radiation exposure.

Skyshine is a physical phenomena where nitrogen-16 gamma radiation emitted skyward from the steam bearing components in the turbine building during radioactive decay interacts with air molecules and is scattered back down to the ground where it can expose members of the public. Since there is significantly less shielding above the steam-bearing components in the turbine building than on the sides of these components, skyshine from nitrogen-16 gammas can be a significant contributor to dose rates outside plant buildings. In addition, the practice of injecting hydrogen into the reactor coolant to reduce SCC significantly increases the fraction of nitrogen-16 in the reactor water that is released into the steam during power operations. The impact of HWC to offsite dose was included in the CLTP and for the CPPU. The licensee performed direct and skyshine radiation dose rate calculations at offsite locations from turbine and condensate equipment to reflect EPU conditions using design-basis sources, including the effect of the plant with HWC and modeling of onsite radiation sources that contribute to offsite dose. The result of the calculations determined that a member of the public would receive the highest dose from skyshine and direct radiation at the Towers Club WSW Sector. The licensee stated that the majority of the offsite dose results from the direct radiation of transport and storage of radioactive materials. These sources of radioactive materials are transported to and stored in the low-level radwaste storage facility, interim spent fuel storage installation, dry active waste reduction system facility, and CSTs. Based on the above calculations, the annual dose to a member of the public from direct radiation and skyshine radiation is 12.2 mrem and 0.406 mrem, respectively. As stated above, the contribution to offsite dose from liquid waste is negligible for the CPPU. Therefore, for post-EPU conditions, based on the annual dose to the member of the public from skyshine and direct radiation of 12.6 mrem and gaseous and liquid effluents of 0.771 mrem, the annual dose to a member of the public from all radiation sources is 13.4 mrem at the Towers Club WSW Sector. This is well within the dose criterion of 25 mrem per year in 40 CFR Part 190.

Operational Radiation Protection Program

The increased production of nonvolatile fission products, actinides, and corrosion and wear products in the reactor coolant may result in proportionally higher plateout of these materials on the surfaces of, and low-flow areas in, reactor systems. The corresponding increase in dose rates associated with these deposited materials is an additional source of occupational exposure during repair and maintenance of these systems. However, the current ALARA program practices at SSES Units 1 and 2 (e.g., work planning, radiation areas access controls) and the existing radiation exposure procedural controls will be able to compensate for the anticipated increases in dose rates associated with this EPU. Therefore, the increased radiation sources resulting from this proposed EPU, as discussed above, 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 and ALARA.

<u>Conclusion</u>

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 ALARA. The NRC staff further concludes that the proposed EPU meets the requirements of 10 CFR Part 20, Appendix I to 10 CFR Part 50, NUREG-0737, and GDC 19. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to radiation protection and its ability to ensure that occupational radiation exposures will be maintained ALARA.

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 conducted its human factors evaluation to ensure that operator performance would not be adversely affected as a result of system and procedure changes made to implement the proposed CPPU. The NRC staff's review covered changes to operator actions, human-system interfaces, and procedures and training needed for the proposed CPPU. The NRC's acceptance criteria for human factors are based on GDC 19; 10 CFR 50.120, "Training and Qualification of Nuclear Power Plant Personnel"; 10 CFR Part 55, "Operator's Licenses"; and the guidance in GL 82-33, "Supplement 1 to NUREG-0737—Requirements For Emergency Response Capability," dated December 17, 1982. SRP Sections 13.2.1, 13.2.2, 13.5.2.1, and Chapter 18.0 contain specific review criteria.

2.11.1 Changes in Emergency and Abnormal Operating Procedures

This section evaluates how the proposed CPPU will change the plant EOPs and abnormal operating procedures (AOPs) (SRP Section 13.5.2.1).

The LAR stated that the licensee will modify current EOPs and AOPs to reflect the effects of the CPPU conditions specific to each unit. The NRC staff sent an RAI to the licensee on April 12, 2007 (Reference 56), which requested clarification of these specific changes to the EOPs and AOPs for both units. The licensee responded to the RAI by letter on May 3, 2007 (Reference 57), by providing a list of all EOPs and AOPs that will be revised for CPPU implementation. In addition, the licensee indicated that it will revise all EOPs and AOPs for the setpoints and plant parameters that will be affected by the proposed CPPU implementation.

The following are EOP changes for both units:

- Discharge pressure for the condensate pumps will be increased to provide additional suction pressure for the RFPs.

- The heat capacity temperature limit curve will reflect the increase in decay heat loading to the suppression pool during certain accidents.

- The licensee will revise the EOPs that involve the use of the SLCS for CPPU conditions. The standby liquid control (SLC) boron-10 concentration will be enriched from 19 to 88 percent, thereby allowing a reduction in SLC tank volume and the hot shutdown boron weight tank level. The SLC logic is also being changed to operate one SLC pump instead of two SLC pumps. In addition, the EOP step that stops the SLC pumps will change from a tank level of 200 gallons to 0 gallons to ensure that the cold shutdown boron weight is injected.

- The licensee will revise the minimum debris retention injection rate time values specified in the EOPs because of the increased reactor power level and increase in decay heat load.

The following are AOP changes for both units:

- The licensee will change the AOPs to reflect the Appendix R modifications to the RHR system. The current procedural guidance and system design only allows one RHR system to be operated in the SPC mode between both units during an Appendix R fire, requiring the control room operators to alternate cooling between the units. The Appendix R modifications will allow one RHR-SPC loop to operate continuously on each unit during an Appendix R fire event.

- The licensee will revise the procedures associated with the condenser offgas treatment system to reflect the increase in dilution steamflow to the offgas recombiner to keep hydrogen gas concentration less than 4 percent.

- Procedures associated with grid disturbances and instabilities will be revised to reflect the operation of the main generator closer to its design capability with the implementation of the CPPU and the addition of capacitor banks in the switchyards.

- The licensee will revise the CWS and SWS procedures to address increased heat load on both systems because of the CPPU implementation. The licensee will add procedural steps to run both the reactor building and turbine building HVAC chillers in parallel, if necessary.

- The AOPs and normal operating procedures have changed to accommodate the usage of a new digital power range neutron monitoring system, which was installed in both units within the past year to support operation under the ARTS/MELLLA and CPPU conditions.

- The licensee will revise the AOPs the increased condensate pump discharge pressure.

- Percent reactor power references associated with increased steamflow through the turbine will be revised in the AOPs.

The NRC staff made additional inquiries in its RAI dated April 12, 2007 (ADAMS Accession No. ML071000126), and in a teleconference on June 7, 2007, as to whether the above AOP and EOP revisions would include new operator actions and/or revised operator action response times. The licensee responded in its letter dated May 3, 2007 (ML071360023), that no new operator actions were being introduced and reiterated in a June 13, 2007, teleconference that the SSES Unit 1 and 2 FSAR does not credit the existing manual operator action response times. The licensee will use the SSES plant procedure program under Appendix B to 10 CFR Part 50, which will oversee all EOP and AOP changes before and after CPPU implementation. The licensee will also revise the operator training program to include revisions to the EOPs and AOPs made for CPPU conditions on both units.

The NRC staff has not identified any new operator actions, adverse procedural changes, or changes to accident mitigation philosophies in the EOPs and AOPs related to the CPPU. In reviewing the changes to the EOPs and AOPs, the revisions are based upon setpoints and plant parameters that will be affected when both units operate under CPPU conditions. The licensee has stated that it will incorporate all of the above EOP and AOP changes into its operator training program before CPPU implementation. Therefore, the NRC staff finds the licensee's proposed changes to SSES Unit 1 and 2 EOPs and AOPs to be acceptable.

2.11.2 Changes to Operator Actions Sensitive to Power Uprate

This section evaluates any new operator actions needed as a result of the proposed CPPU and changes to any current operator actions related to EOPs or AOPs that will occur as a result of the proposed CPPU (SRP Chapter 18.0).

The licensee stated in its submittal and response to the NRC staff's RAI that the CPPU will not introduce any changes to existing operator actions for abnormal and emergency conditions. The current automatic safety functions related to abnormal and emergency conditions will remain intact after CPPU implementation. However, the licensee did identify one new manual operator action and an additional plant modification to be used for Appendix R events to support CPPU conditions.

The licensee will install two manual isolation bypass header valves, one for each of the two divisions of the UHS spray system, to enhance the capability of the UHS in dissipating decay heat. The licensee will modify the RHRSW operating procedure to account for this enhancement to the UHS by adding a manual operator action. This new manual operator action will be credited in the licensee's revised safety analysis and requires a plant operator to close a manual isolation bypass header valve in the bypass line for which the associated motor-operated bypass header valve fails to isolate. The licensee stated in its May RAI response and in the June 13, 2007, teleconference that this new manual action is required to be performed within 3 hours of a design-basis LOCA event in one unit and a shutdown of the other unit in order to maintain the UHS design temperature of 97 °F. As described in the licensee's submittal and in the June 27, 2007, supplemental document, the modification will serve as a compensatory action referenced in the EOPs by directing the operators to follow the RHRSW operating procedure to isolate the bypass header. If the bypass header fails to isolate, the RHRSWS and ESWS heat loads on the affected loop cannot be adequately cooled. The licensee will revise this operating procedure to provide the operators an instruction to verify that no flow exists through the bypass header after operating the motor-operated bypass header valves for both bypass lines. The task will be performed by a locally dispatched plant operator to observe flow from the end of the bypass header pipe. If flow is observed from the end of the bypass header pipe because of the failure of the motor-operated bypass header valve to close in either bypass line, the operating procedure will direct the plant operator to manually close the manual isolation bypass header valve in the affected bypass line. The operator will perform the action by using a reach rod to turn the valves located in a valve vault, located outside near the reactor building and the ESW pumphouse. The licensee plans to use procedural guidance and additional administrative controls to ensure the appropriate accessibility and usage of the reach rod.

The licensee also stated in its submittal that the Appendix R modifications will be made to increase equipment capabilities for containment cooling to address the increased decay heat as a result of the CPPU. As discussed in Section 2.11.1 of this SE, the licensee intends to operate one RHR-SPC loop continuously on each unit during an Appendix R fire event. The licensee plans to add a new control, which will be located in both units, to allow the operators to operate one RHR loop in the SPC mode continuously for both units, as directed by the revised AOPs. The licensee stated that the modification will not result in any new manual operator actions and will eliminate an existing manual operator action to locally alternate one RHR loop between both units during an Appendix R fire event.

The NRC staff reviewed the licensee's submittal for the effects of the CPPU on existing operator actions as well as new operator actions. As discussed above, the licensee identifies two changes with respect to operator actions to support the CPPU: (1) the manual operator actions associated with the UHS system and (2) additional plant modification to be used for Appendix R events. The licensee provided detailed information of both items in its RAI response (Reference 57). The NRC staff has not identified any adverse effects of the CPPU-related changes with regards to other existing emergency operator actions unaffected by CPPU implementation. Additionally, the licensee will take credit for the new manual operator action in the revised UFSAR that is associated with the UHS modification for CPPU conditions. The licensee's Appendix R modifications to allow one loop of the RHR-SPC to operate continuously in each unit will allow the operators to perform other mitigation activities during emergency conditions. The licensee will reflect both of these changes in the SSES Unit 1 and 2 procedure change program and operator training program before CPPU implementation. The NRC staff finds the licensee's proposed changes addressing operator actions under CPPU conditions to be acceptable.

2.11.3 Changes to Control Room Controls, Displays, and Alarms

This section evaluates any changes the proposed CPPU will have on the operator interfaces for control room controls, displays, and alarms (SRP Chapter 18.0).

In its response to the NRC staff's RAI, the licensee listed several control room controls, alarms, and displays to be revised for CPPU implementation for both units. As discussed in Section 2.11.1, the licensee will revise all EOPs and AOPs related to the affected items to reflect the setpoint and plant parameter changes resulting from the CPPU. In addition, the licensee plans to revise the EOPs and AOPs affected by the control room modifications to be made for CPPU conditions for both units.

The licensee is modifying the SLC to use enriched boron-10. Subsequent changes in the control room will include modification of the SLC pump control switch to operate one SLC pump during a system initiation instead of two SLC pumps, reduction of the normal level indicator for the SLC tank, and reduction of the indicator for the heat trace temperature. The licensee implemented the changes for Unit 2 in the spring of 2007 and will implement the changes for Unit 1 in the spring of 2008. The licensee stated that the operators will have 1 year of experience with the Unit 2 SLC modifications before the CPPU is implemented on Unit 1 in 2008.

The licensee will install new key lock switches in the upper relay room to bypass the RFP low flow signal when an RFP is out of service. When the switches are in the "bypass" position, a control room annunciator alarm will be generated. This change was implemented on Unit 2 in the Spring of 2007 and will be implemented for Unit 1 in the Spring of 2008. The licensee stated that the operators will have 1 year of experience with new system configuration before the CPPU is implemented on Unit 1 in 2008.

The licensee will increase the required minimum flow setpoints for condensate pumps to account for the new condensate pump impeller modifications. The change has been made for Unit 2 and will be implemented on Unit 1 in the spring of 2008. The licensee stated that the operators will have 1 year of experience with the Unit 2 condensate system modifications before the CPPU is implemented on Unit 1 in 2008.

The NRC staff has reviewed the licensee's changes to control room controls, displays, and alarms related to the CPPU as listed in the RAI response. The controls and indicators described above were modified for Unit 2 in 2007. The licensee will make similar control room modifications for Unit 1 before its CPPU implementation in 2008. The licensee stated that these changes, as well as the list of changes described in the licensee's RAI response, will not impact the operators' ability to address abnormal and emergency scenarios under CPPU conditions. The licensee has emphasized that all control room changes will be incorporated into its operator training program and reflected on the simulator before CPPU implementation. To provide training to the control room crews on the initial differences between Unit 1 and Unit 2, the licensee will provide two software packages for the simulator that will reflect both the operations of Unit 1 and Unit 2 for the applicable uprated conditions. The NRC staff finds the licensee's proposed changes to the control rooms for SSES Units 1 and 2 to be acceptable.

2.11.4 Changes on the Safety Parameter Display System

This section assesses any changes to the safety parameter display system (SPDS) resulting from the proposed CPPU and the means by which the operators will know of the changes (SRP Chapter 18.0).

The licensee stated in its submittal that the SPDS is not being modified for the CPPU except for the following:

> The Heat Capacity Temperature Limit graphic in the "Heatcap" display will be revised to reflect the additional decay heat from the CPPU.

The NRC staff reviewed the licensee's submittal and RAI response concerning changes to the SPDS display and did not identify any changes that would adversely impact the SPDS upon CPPU implementation. The changes to the SPDS will reflect the effects of increased decay heat on the plant parameters. The licensee will use operator training and the simulator to make the operators aware of the changes to the SPDS before CPPU implementation. The NRC staff finds the licensee's proposed changes to the SSES Unit 1 and 2 SPDS to be acceptable.

2.11.5 Changes to the Operator Training Program and the Control Room Simulator

This section evaluates any changes to the operator training program and the plant-referenced control room simulator resulting from the proposed CPPU and the implementation schedule for making the changes (SRP Sections 13.2.1 and 13.2.2).

The licensee stated in its submittal that the Operations Training Group at SSES Units 1 and 2 will provide training on all modifications installed that affect each unit's operation before CPPU implementation. This training will be provided on the simulator and in the classroom. The content of the training for the CPPU will depend on the CPPU power ascension plan and the CPPU-related modification implementation schedule. The Operations Training Group will develop lesson plans to cover plant modifications, all procedure changes, control room modifications, and SPDS changes before CPPU implementation on Unit 2 in 2009 and on Unit 1 in 2008.

The training will also include procedural actions to achieve the CPPU RTP level for each unit, power ascension testing, and comparison of plant conditions between the current RTP level and the CPPU RTP level. The simulator is currently a duplicate of the Unit 1 control room. The hard-wired instrumentation on the simulator will not reflect the CPPU range scales until all CPPU-related control room modifications have been completed before CPPU implementation on Unit 1 in 2008. However, the simulator's plant integrated computer system displays will be modified with a software package specific to Unit 2 to provide full instrumentation range scales for CPPU conditions. The software package will also aid in training operators on CPPU-related operations, transients, and emergency scenarios.

The NRC staff inquired about the licensee's plan for scheduling the operator training needed to address all plant modifications, procedural revisions, control room changes, and other hardware changes to be affected by the CPPU. The licensee stated in its RAI response that CPPU-based operator training was initiated in 2005 for Unit 1 (because of the pending installation of the power range neutron monitoring system in 2006). This training was initiated in 2006 for Unit 2 on the various CPPU-related modifications made in the spring of 2007. Two cycles of operator training were later completed before the refueling outage on Unit 2 in 2007. Before startup following the 2007 outage, the operators were given just-in-time training to cover the CPPU-related plant modifications that were made at that time. The just-in-time training also included startup training and startup testing evolutions on the simulator. In the fourth quarter of 2007, operator training will focus on the Unit 1 modifications to be installed in the spring of 2008 on Unit 1 and on the CPPU power ascension plan. Just-in-time training to cover last-minute items and perform startup training and startup testing evolutions on the simulator will also be provided. Similarly, CPPU-related classroom, simulator, and just-in-time training will be provided in 2009 and 2010 as the CPPU-related modifications are fully installed on both units.

The licensee also stated that the operators observed transient demonstrations and received training on simulator transients for the CPPU-modified systems during the fourth quarter of 2006 and the first quarter of 2007 at the pre-CPPU licensed power levels. CPPU training on the simulator at the increased power levels will begin in late 2007. The licensee will also collect operating data during CPPU implementation and startup testing. The collected data will be compared to simulator data as required by Section 5.4.1 of ANSI/ANS-3.5-1985, "Nuclear Power Plant Simulators for Use in Operator Training and Examination." The licensee will then conduct simulator acceptance testing to benchmark the simulator performance based on design and engineering analysis data, as also required by ANSI/ANS-3.5-1985.

The NRC staff has reviewed the licensee's submittal and RAI response with regard to operator training and the simulator related to the CPPU. The licensee has developed and implemented a satisfactory training program to address current and pending revisions to the EOPs and AOPs, changes to the control room for Units 1 and 2, plant modifications related to the CPPU, and changes made to the SPDS. The licensee also plans to revise the simulator software programs as necessary for operator training. The NRC staff finds the licensee's proposed changes to the SSES operator training program and plant simulator to be acceptable.

Conclusion

The NRC staff has reviewed the licensee's submittal describing its identified changes to operator actions, human-system interfaces, procedures, and operator training required for the proposed CPPU and concluded that the licensee has (1) appropriately accounted for the effects of the proposed CPPU on the procedures and (2) taken appropriate actions to ensure adequate operator training addressing the changed conditions resulting from the CPPU. The NRC staff further concludes that the proposed changes will continue to meet the requirements of GDC 19, 10 CFR 50.120, and 10 CFR Part 55 following implementation of the proposed CPPU. Therefore, the NRC staff finds the licensee's proposed CPPU acceptable with respect to the human factors aspects of the required system changes.

2.12 Power Ascension and Testing Plan

The technical bases for this request follow the guidelines contained in the NRC-approved CLTR (NEDC-33004P-A) (Reference 10), which the NRC determined to be an acceptable methodology for requesting EPUs. However, the NRC reserved the right to consider on a plant-specific basis the CLTR recommendation against performance of large transient testing (e.g., MSIV closure and generator load rejection). SRP Section 14.2.1 describes the NRC staff guidance for reviewing EPU test programs. The NRC staff focused on whether PPL adequately addressed the guidance described in the SRP.

Regulatory Evaluation

The purpose of the EPU test program is to demonstrate and 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 (1) plans for the initial approach to the proposed maximum licensed thermal power level, including verification of adequate plant performance, (2) steady-state and transient performance testing sufficient to demonstrate, in conjunction with plant operating experience, computer modeling, and analyses, that SSCs will perform satisfactorily at the requested power level, and (3) the test program's conformance with applicable regulations.

The NRC's acceptance criteria for the proposed EPU test program are based, in part, on (1) Criterion XI, "Test Control," in Appendix B to 10 CFR Part 50, which requires establishment of a test program to demonstrate that SSCs will perform satisfactorily in service, (2) GDC 1, 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, (3) 10 CFR 50.34, which specifies requirements for the content of the original operating license application, including FSAR plans for preoperational testing and initial operations, and (4) Chapter 5 of Appendix A to RG 1.68, "Initial Test Programs for Water-Cooled Nuclear Power Plants," which generally limits tests to those that demonstrate that the facility operates in accordance with design both during normal steady-state conditions and, to the extent practical, during and following AOOs. SRP Section 14.2.1 contains specific review and acceptance criteria for the EPU test program.

2.12.1 SRP Section 14.2.1, Section III.A—Comparison of Proposed Test Program to the Initial Plant Test Program

Evaluation Criteria

Section III.A of SRP Section 14.2.1 specifies the guidance and acceptance criteria that the licensee should use to compare the proposed EPU testing program to the original power ascension test program performed during initial plant licensing. The EPU test program should address the following specific criteria:

- all power ascension tests initially performed at a power level of equal to or greater than 80 percent of the OLTP level

- all initial test program tests performed at power levels lower than 80 percent of the OLTP level that would be invalidated by the EPU

- differences between the proposed EPU power ascension test program and the portions of the initial test program identified by the previous criteria

The licensee shall either repeat initial power ascension tests within the scope of this comparison or adequately justify proposed test deviations.

Technical Evaluation

The NRC staff reviewed Chapter 14 of the SSES Unit 1 and 2 UFSAR, which presented a general purpose, description, and acceptance criteria for the initial startup testing. The NRC staff reviewed additional information that described the startup and power test program performed to demonstrate that the plant is capable of operating safely and satisfactorily. The NRC staff also reviewed the following information:

- Section 14.2 of the SSES Unit 1 and 2 UFSAR provided an overview of the test descriptions, objectives, methods, and acceptance criteria associated with the initial power ascension test program from initial fuel loading through 100-percent power.

- Attachment 6 to PLA-6076 is a nonproprietary version of the PUSAR that provided an integrated summary of the results of the safety analysis and evaluations performed specifically for the SSES Unit 1 and 2 CPPU.

- Attachment 7 to PLA-6076 provided a listing of planned modifications necessary to support EPU.

- Attachment 8 to PLA-6076 supplements Section 10.4 of the PUSAR and provides additional information about startup testing, EPU testing at the power levels specified in Attachment 7, and a comparison of the SSES Unit 1 and 2 initial startup testing and planned EPU testing, as discussed in SRP Section 14.2.1. The attachment also includes a justification for exceptions to performing large transient testing.

- Attachment 12 to PLA-6076 provides a markup of the review matrices contained in the RS-001, with cross-references to the CLTR, as well as the SSES Unit 1 and 2 PUSAR and FSAR.

The NRC staff found that Table 1 of PPL Attachment 8 lists all transient tests described in the initial startup test program, as derived from UFSAR Section 14.2. Additionally, Section 4.0 of Attachment 8 provides a table of initial startup transient tests performed at greater than 80 percent of the OLTP. These included closure of all MSIVs (ST-25) performed at 100 percent of the OLTP for both units and a turbine trip/generator load rejection test (ST-27) performed at 100 percent of the OLTP for Unit 1 and 97 percent of the OLTP for Unit 2, and they follow the tests described in Attachment 2 of SRP Section 14.2.1. Table 3 of Attachment 8 presents the startup tests PPL intends to perform for the EPU. The PPL power ascension and test program (PATP) does not include performing large transient testing, specifically an MSIV closure test and a generator load rejection test at full-EPU power level. PPL presented its justification for not performing such tests in Attachment 8 of its application; Section 2.12.3 of this SE further discusses this topic.

Testing will be performed in accordance with the TS surveillance requirements (SRs) and applicable procedures on instrumentation recalibrated for CPPU conditions. Steady-state and transient data will be collected during power ascension and continue at each EPU power increase increment. CPPU power increases will be made in predetermined increments of less than or equal to 5 percent power. Power ascension will occur over a period of time with gradual increases in power and hold periods. PPL is also performing postmodification testing, calibration, normal surveillance, and power ascension testing, as required, to ensure that systems will operate in accordance with their design requirements.

Conclusion

With the exception of the NRC staff's review of the PPL justification for not performing large transient testing, discussed in Section 2.12.3 of this SE, the NRC staff concludes through review of the documents referenced above, including a review of the initial startup and test program described in Section 14.2 of the SSES Unit 1 and 2 UFSAR, that the proposed EPU test program adequately identified (1) all initial power ascension transient tests performed at a power level of equal to or greater than 80 percent of the OLTP level and (2) all initial test program tests performed at power levels lower than 80 percent of the OLTP level that would be invalidated by the EPU. The NRC staff also concluded that, with respect to the program implementation methodology, the PPL power ascension test program is acceptable and in conformance with the applicable regulations.

2.12.2 SRP Section 14.2.1, Section III.B—Postmodification Testing Requirements for SSCs Important to Safety Impacted by EPU-Related Plant Modifications

Evaluation Criteria

Section III.B of SRP Section 14.2.1 specifies the guidance and acceptance criteria that 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 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 a LOOP, tripping of the main T-G 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 three criteria:

(1) EPU-related modifications impact the performance of the SSC.
(2) The SSC is used to mitigate an AOO described in the plant-specific design basis.
(3) The program involves the integrated response of multiple SSCs.

The EPU test program should identify the following as they pertain to the above paragraph and criteria:

- plant modifications and setpoint adjustments necessary to support operation at EPU conditions

- changes in plant operating parameters (e.g., reactor coolant temperature, pressure, average temperature, reactor pressure, flow) resulting from operation at EPU conditions

Technical Evaluation

The NRC staff reviewed Attachment 7 to the application and Table 2 of Attachment 8 (Reference 1), which described completed and planned modifications for CPPU implementation. PPL stated that based on the list of modifications in Table 2, the aggregate impact of most of these modifications on plant operations is minimal. PPL plans to complete these modifications during five refueling outages. The modifications necessary to support the EPU are currently scheduled through the spring of 2010. The NRC staff also reviewed Section 4.2 of Attachment 8, which discussed the PPL aggregate impact analysis of the modifications necessary to support the CPPU. PPL stated that the aggregate impact of EPU plant modifications, setpoint adjustments, and parameter changes will be demonstrated by a test program established by GE and in accordance with startup test specifications as described in PUSAR Section 10.4. Postmodification testing associated with the modifications proposed by PPL includes functional performance checks, component performance measurements, equipment calibrations, physical and nondestructive examination inspections, and pressure drop measurements at full-flow conditions. The startup test specifications are based upon analyses and GE BWR experience with uprated plants to establish a standard set of tests for initial power ascension for the CPPU, and they supplement the normal TS testing requirements. PPL stated that the CPPU testing program at SSES Units 1 and 2 has been reviewed and is [[
]]

Conclusion

The NRC staff concludes that the testing program proposed by PPL adequately demonstrates that EPU-related modifications will be adequately implemented. Specifically, the NRC staff concludes that based on a review of the PPL list of completed and planned modifications, including postmaintenance testing associated with these modifications, the proposed EPU test program should adequately demonstrate the performance of SSCs important to safety. The NRC staff concludes that the program includes those SSCs (1) impacted by EPU-related modifications, (2) used to mitigate AOOs described in the plant design basis, and (3) that support a function that relies on integrated operation of multiple systems and components. The NRC staff also concludes that the proposed PATP adequately identified plant modifications necessary to support operation at the uprated power level and complies with the criteria established in Section III.B of SRP Section 14.2.1.

2.12.3 SRP Section 14.2.1, Section III.C—Justification for Elimination of EPU Power Ascension Tests

Evaluation Criteria

Section III.C of SRP Section 14.2.1 specifies the guidance and acceptance criteria that 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 performed, provided that proposed exceptions are adequately justified in accordance with the criteria provided in Section III.C.2. Each secondary review branch is to verify the adequacy of the licensee's justification for test exceptions that are within the branch's technical area of review. 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 the elimination of power ascension tests:

- previous operating experience
- introduction of new thermal-hydraulic phenomena or identified system interactions
- facility conformance to limitations associated with analytical analysis methods
- plant staff familiarization with facility operation and trial use of operating procedures and EOPs
- margin reduction in safety analysis results for AOOs
- guidance contained in vendor topical reports
- risk implications

Technical Evaluation

The NRC staff's review is intended to provide reasonable assurance that the performance of plant equipment important to safety that could be affected by integrated plant operation or transient conditions is adequately demonstrated before extended operation at the requested EPU power level. The NRC staff recognizes that licensees may propose a test program that does not include all of the power ascension testing referred to in Sections III.A and III.B that would normally be performed, provided that proposed exceptions are adequately justified in accordance with the criteria provided in Section III.C.2. If a licensee proposes to omit certain original startup tests from the EPU testing program based on favorable operating experience, the applicability of the operating experience to the specific plant must be demonstrated. Plant design details such as configuration, modifications, and relative changes in setpoints and parameters, equipment specifications, operating power level, test specifications and methods, operating procedures and EOPs, and adverse operating experience from previous EPUs should be considered and addressed.

SRP Section 14.2.1 specifies that the EPU test program should include steady-state and transient performance testing sufficient to demonstrate that SSCs will perform satisfactorily at the requested power level and that EPU-related modifications have been properly implemented. The SRP provides guidance to the NRC staff in assessing the adequacy of the licensee's evaluation of the aggregate impact of EPU plant modifications, setpoint adjustments, and parameter changes that could adversely impact the dynamic response of the plant to AOOs.

In this section of the SE, the NRC staff reviewed the licensee's justification for not performing certain original startup tests against the review criteria established in SRP Section 14.2.1. PPL presented its justification in Attachment 8 of its application (Reference 1). To assist in the NRC staff's review, PPL provided a table that cross-referenced the review criteria contained in Section III.C.2 of SRP Section 14.2.1 to the PPL discussion in Attachment 8. The PPL PATP does not include all of the power ascension testing that would typically be performed during initial startup of a new plant. PPL provided a detailed discussion of the basis for eliminating certain large transient testing pursuant to the review criteria established in Section III.C.2 of SRP Section 14.2.1. The following large transient tests were performed during initial startup, as discussed in the SSES Unit 1 and 2 UFSAR:

- Closure of All MSIVs. In accordance with Chapter 14.2, page 241, of the SSES Unit 1 and 2 UFSAR, this initial startup test (ST-25) required a simultaneous full closure of all MSIVs and was performed for both units at 100 percent of the OLTP. The test objectives were to functionally check the MSIVs for proper operation at selected power levels, determine isolation valve closure times, and determine reactor transient behavior during and following simultaneous closure of all MSIVs.

- Turbine Trip/Generator Load Rejection. In accordance with Chapter 14.2, page 244, of the SSES Unit 1 and 2 UFSAR, this initial startup test (ST-27) was performed at 100 percent of the OLTP for Unit 1 and 97 percent of the OLTP for Unit 2. The test was performed to demonstrate the response of the reactor and its control systems to protective trips in the turbine and generator and to demonstrate the capacity of the turbine bypass valves. Section 14.2 of the SSES Unit 1 and 2 FSAR describes the acceptance criteria and testing methods for this test.

With respect to the review criteria established in SRP Section 14.2.1, Section III.C.2, PPL cited industry events that occurred at greater than original power levels at BWR-4 units that are similar in design to SSES Units 1 and 2 that resulted in several examples of plant response to MSIV closure and load reject events. The PPL assessment of the industry events indicated that the plants responded as expected in accordance with their design features, that no unexpected conditions were experienced, and that no latent defects were uncovered in these events beyond the specific failures that actually initiated the events.

For example, PPL cited several events at Plant Hatch Unit 1, including a turbine trip and a generator load reject event subsequent to its uprate, as reported in licensee event reports (LERs) LERs 2000-004 and 2001-002. According to the LERs, the primary safety systems behaved as expected, indicating that the analytical models being used are capable of modeling plant behavior at EPU conditions. Plant Hatch Unit 2 also experienced an unplanned event in May 1999 that resulted in a generator load reject from 98 percent of rated power. As noted in Southern Nuclear Operating Company's LER 99-005, no anomalies were seen in the plant's response to this event. The NRC had previously granted both units at Plant Hatch an EPU without the requirement to perform large transient testing.

PPL also cited the Brunswick Steam Electric Plant, Units 1 and 2, as another example of a similar BWR-4 plant that was licensed to 120 percent of the OLTP. An unplanned event at Unit 2 resulted in a generator trip at 115.2 percent of the OLTP (96 percent of uprated thermal power) in 2003. PPL stated that LER 2003-04 reported that no anomalies were experienced in the plant's response to this event and no new plant behaviors were observed. On January 12, 2003, Unit 1 experienced a turbine trip at 94 percent RTP, as reported in LER 2003-01. The required equipment responded as designed and the Group 2 and 6 valves isolated.

In addition, PPL cited the actual plant transients experienced at SSES Units 1 and 2 as another factor to justify not performing large transient testing. Since initial startup, SSES has experienced an MSIV closure event and a turbine trip/full-load rejection event. On July 1, 1999, a full MSIV closure event occurred in Unit 1 when the inadvertent closure of one MSIV resulted in an indication of high steamflow in the remaining three steamlines. Data recorded during the event demonstrated that the plant responded as expected and that resulting parameters were well within guidelines and requirements. Section 2.2.4 of this SE further discusses the NRC staff's review of the capability of the MSIVs to close in the manner assumed by PPL for EPU conditions.

On June 6, 2005, a turbine trip/full-load rejection event occurred in Unit 2 as a result of an electrical transient that caused a trip of both recirculation pumps. PPL stated that during the event, RV pressure remained fairly stable and varied as expected, two SRVs opened and then closed, bypass valves operated successfully, and there were no challenges to the containment.

The licensee stated that information obtained regarding testing and responses to unplanned transients for both Hatch and Brunswick units during post-EPU operation have shown that the plants responded as expected and in accordance with their design features. The licensee also stated that no new thermal-hydraulic phenomena or new system interactions were identified; no unique limitations associated with conformance to analytical methods were identified; plant operators will be trained on various plant upset conditions from postulated accident conditions to anticipated transients; no change in design and pressure margins were identified; and PPL has complied with NRC staff-approved guidance contained in GE LTRs, which the NRC staff concluded meets the objectives of a suitable test program for the CPPU.

Plant Transient Evaluation

The licensee conducted a risk assessment for performing the two large transient tests upon EPU implementation, as discussed in Attachment 8, Section 6.0, of the application. The licensee concluded that from a risk perspective, large transient testing should not be performed unless clear benefits can be achieved that cannot otherwise be obtained through an unplanned event. Since the proposed EPU was not submitted as a risk-informed LAR, the NRC staff did not perform a detailed review of the licensee's risk assessment. The NRC staff recognizes that any transient, even those intentionally initiated under prestaged testing conditions, will subject the plant to a challenge that will pose some risk to public health and safety. As such, a large transient involving a scram from high power levels should not be incurred unnecessarily. Therefore, the NRC staff finds that large transient testing will subject the plant to a challenge that involves a small increase in risk and, from a risk perspective, should not be required unless it is determined that the benefits of this testing cannot be achieved through other methods and the benefits outweigh the small increased risk.

The NRC staff's review of the licensee's justification for not performing large transient testing from a reactor systems perspective focused on the licensee's plant-specific assessment provided in the Attachments 4 and 8 of the SSES Unit 1 and 2 EPU submittal. Part of the PPL justification discussed transient experience at high power and for a wide range of operating power levels at operating BWR plants, which has shown an acceptable correlation of the plant transient data to the predicted response. The operating history of SSES Units 1 and 2 demonstrates that previous transient events were within expected peak limiting values. The transient analysis performed for the SSES Unit 1 and 2 CPPU demonstrated that all safety criteria are met and that this uprate did not cause any previous nonlimiting events to become limiting.

The licensee also stated that based on the similarity of plants, past transient testing, operating experience, past analyses, and the evaluation of test results, the effects of the CPPU RTP level can be analytically determined on a plant-specific basis. No new design functions that would necessitate modifications and no large transient testing validation are required of safety-related systems for the CPPU. The instrument setpoints that will be changed do not contribute to the response to large transient events. No physical modification or setpoint changes will be made to the SRVs, and no new systems or features will be installed for mitigation of rapid pressurization AOOs for this CPPU. A scram from a high power level results in an unnecessary and undesirable transient cycle on the primary system. The licensee stated that, therefore, additional transient testing involving a scram from high power levels is not justifiable. Should any future large transients occur, SSES Unit 1 and 2 procedures require identification of any anomalous plant response and verification that all key safety-related equipment, required to function during the event, operated as anticipated or expected. Existing plant event data recorders are capable of acquiring the necessary data to confirm the actual versus expected response. In addition, the limiting transient analyses will be included as part of the reload licensing analysis.

The NRC staff's evaluation found the licensee's justification for not performing large transient testing, as discussed above, to be acceptable based on the following review criteria established in SRP Section 14.2.1, Section III.C.2:

- Previous operating experience has demonstrated acceptable performance of SSCs under a variety of steady-state and transient conditions.

- No new thermal-hydraulic phenomena or identified system interactions are expected to be introduced at the EPU conditions. Because this EPU is a CPPU, the effects on SSCs because of changes in thermal-hydraulic phenomena are limited.

- SSES Units 1 and 2 are in conformance with the limitations associated with applicable computer codes and analytical methods.

- SSES Unit 1 and 2 plant staff will be familiar with facility operation and the use of operating procedures and EOPs.

- Adequate margin in safety analysis results for AOOs are available.

- The licensee has used guidance contained in NRC staff-approved topical reports, which the NRC staff concluded meets the objectives of a suitable test program for the CPPU.

The NRC staff's review of the licensee's power ascension and testing plan for BOP systems focused primarily on two areas. One area deals with the capability of the turbine bypass control system to discharge steam to the main condenser as assumed in the T-G load reject and turbine trip transient analyses. Because the licensee is not proposing to credit additional steam bypass capacity beyond what was previously assumed, transient testing for the purpose of demonstrating the capacity of the turbine bypass control system is not required.

The other area of the NRC staff's review focused on transient testing that may be needed as a consequence of BOP modifications that are necessary for implementing the proposed EPU. In this regard, the NRC staff's based its determination that the condensate and FW system is acceptable for the proposed power uprate in part on the capability of the uprated plant to sustain the loss of a condensate pump or a FW pump (individually) without resulting in a complete loss of reactor FW. This issue, further discussed in Section 2.5.4.4 of this SE, is considered to be an open item.

Conclusion

The NRC staff reviewed the licensee's justification for not performing certain original startup tests against the applicable review criteria established in SRP Section 14.2.1. In justifying test eliminations or deviations, PPL addressed the factors discussed in Section III.C.2 of that section. These factors included a discussion of previous operating experience, introduction of new thermal-hydraulic phenomena or system interactions, conformance with limitations of analytical methods, plant staff familiarization with facility operation and EOPs, margin reduction in safety analysis for AOOs, and risk implications. Additionally, PPL followed the NRC staff-approved guidance contained in GE LTRs, which the NRC staff concluded meets the objectives of a suitable test program for the CPPU.

Based on its review, the NRC staff concludes that the licensee's justification for not performing large transient testing is acceptable in conformance with the guidance in SRP Section 14.2.1.

2.12.4 SRP Section 14.2.1, Section III.D—Adequacy of Proposed Testing Plans

<u>Evaluation Criteria</u>

SRP Section 14.2.1, Section III.D, specifies the guidance and acceptance criteria the licensee should use to develop plans for the initial approach to the increased EPU power level and testing to verify that the reactor plant operates within the values of EPU design parameters. The test plan should ensure 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, the operability of safety-related SSCs relied upon during operation shall be verified in accordance with existing TS and quality assurance program requirements. The EPU test program should identify the following:

- the method in which the 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

- 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

<u>Technical Evaluation</u>

The NRC staff reviewed Attachment 8 of Reference 1, which described the SSES Unit 1 and 2 startup testing plan. The plan specifies the testing that the licensee intends to perform following EPU implementation. Attachment 8 also provides a comparison of initial startup testing and EPU testing. The main elements of the plan supplement the SSES Unit 1 and 2 PUSAR and provide additional information about startup testing. The plan includes power ascension testing, monitoring and analysis, and post-EPU monitoring to ensure the safe operation of SSES Units 1 and 2. PUSAR Section 10.4, submitted with the licensee's application in Attachment 6, provides additional information relative to power uprate testing and describes a standard set of tests that supplement the normal TS testing requirements and that have been established for the initial power ascension steps of the CPPU. The PUSAR is an integrated summary of the results of the safety analysis and evaluations performed specifically for the SSES Unit 1 and 2 EPU. The test schedule would be performed in an incremental manner, with appropriate hold points for evaluation, and contingency plans would be used if predicted plant response is not obtained.

As previously stated in Section 2.12.3 of this SE, the NRC staff found that Table 1 of Attachment 8 lists all transient tests described in the initial startup test program, as derived from UFSAR Section 14.2. The licensee also provided in Section 4.1 of Attachment 8 a table listing power ascension transient tests that were initially performed at greater than 80 percent of the OLTP. These tests follow the tests described in Attachment 2 to SRP Section 14.2.1.

Conclusion

The NRC staff has reviewed the licensee's EPU test program, including its conformance with applicable regulations and the guidance in SRP Section 14.2.1. The NRC staff concludes that the proposed EPU test plan will adequately ensure that the test objectives, test methods, and test acceptance criteria are consistent with the design basis for the facility.

Summary Conclusion

The NRC staff has reviewed the licensee's EPU power ascension and testing program, including plans for the initial restart and approach to achieve the proposed maximum licensed thermal power and the conformance of the licensee's overall test program with applicable regulations and the guidance in SRP Section 14.2.1. The NRC staff evaluated the licensee's plans for the initial approach to the proposed maximum licensed thermal power level, including verification of adequate plant performance, and the test program's conformance with applicable regulations. The licensee's test program primarily includes steady-state testing with no large transient testing proposed.

The NRC staff also reviewed the licensee's justification for not performing large transient testing, presented in Attachment 8 to the application. The NRC staff determined that the licensee's justification, as previously discussed in Section 2.12.3 of this SE, is acceptable based on the applicable review criteria discussed in Section III.C.2 of SRP Section 14.2.1.

Subject to the satisfactory resolution of the license condition associated with transient testing of the condensate and FW system discussed in Section 2.5.4.4 of the SE, the NRC staff concludes that the proposed EPU test program provides adequate assurance that the plant will operate as expected and in accordance with design criteria and that SSCs affected by the proposed EPU, or modified to support the proposed EPU, will perform satisfactorily in service. Furthermore, the NRC staff finds that there is reasonable assurance that the EPU testing program satisfies the requirements of Criterion XI in Appendix B to 10 CFR Part 50 and the guidance in SRP Section 14.2.1. Therefore, the NRC staff finds the proposed EPU test program acceptable.

2.13 Risk Evaluation

2.13.1 Risk Evaluation of Extended Power Uprate

The NRC staff reviewed the licensee's risk evaluation to (1) determine if the proposed EPA creates "special circumstances" and (2) ensure that the risks associated with the proposed EPU are acceptable. As described in Appendix D to SRP Chapter 19, special circumstances may be present if any issues are identified that would potentially rebut the presumption of adequate protection provided by the licensee meeting the deterministic requirements and regulations. For this section of the application, the NRC staff's review covered the impact of the proposed CPPU on core damage frequency (CDF) and large early release frequency (LERF) because of changes in the risks associated with internal events, external events, and shutdown operations. In addition, the NRC staff's review addressed the quality of the risk analyses used by the licensee to support the CPPU application. This quality review included a review of the licensee's actions taken to address issues or weaknesses that may have been raised by NRC staff reviews of the licensee's individual plant examinations (IPEs) and individual plant examinations of external events (IPEEEs), by industry peer reviews, or by licensee self-assessments.

The NRC's risk acceptance guidelines, contained in RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," apply to risk-informed changes but can also be used for applications that are not risk informed as one element in providing insights into the impact of implementation of the application on adequate protection. Matrix 13 of RS-001 and its attachments contain specific, risk-related guidance for NRC staff review of EPU applications to aid in determining whether special circumstances exist with respect to a specific, nonrisk-informed, EPU issue.

2.13.2 Technical Evaluation

The SSES Unit 1 and 2 probabilistic risk assessment (PRA) covers internal events and some external events. The licensee's risk evaluation used its plant-specific PRA to compare pre-CPPU risks to those associated with post-CPPU plant design and operation. The licensee used a combination of quantitative and qualitative methods to assess the risk impacts of the proposed CPPU. The following subsections provide the NRC staff's technical evaluation of the risk evaluation provided by the licensee.

2.13.2.1 Probabilistic Risk Assessment Quality

The licensee submitted the SSES Unit 1 and 2 IPE, which addressed internal events and internal flooding events, to the NRC on December 13, 1991, in response to NRC GL 88-20. On October 27, 1997, the NRC issued an SE stating that the NRC staff could not conclude that the SSES Unit 1 and 2 IPE met the intent of GL 88-20 and identified a number of areas of concern. Specifically, the NRC staff noted that the IPE did not provide sufficient evidence to conclude that the licensee appropriately treated common-cause failures, human reliability analysis (HRA), plant-specific failures, and back-end (i.e., containment) analysis, including sensitivity analyses. Based on plant improvements, additional information provided by the licensee, and a NRC staff audit of the SSES Unit 1 and 2 IPE, the NRC staff issued a supplement to the original SE on August 11, 1998, that concluded that the SSES Unit 1 and 2 IPE met the objectives of GL 88-20; with the following weaknesses identified related to the back-end analysis:

- The accident sequence progression was terminated if the containment failed before core damage; assuming all such sequences would go to core damage.
- The impact on conditional containment failure probability of some severe accident phenomena and resulting containment failure modes appears to have been understated.
- The treatment of interfacing system LOCAs was characterized as limited.

In the SSES Unit 1 and 2 IPE SE, the NRC indicated that it believed these remaining issues were unlikely to affect the overall conclusions or impact the licensee's ability to identify vulnerabilities. The licensee indicated that it addressed these remaining issues and incorporated corresponding changes into the SSES Unit 1 and 2 PRA before the BWROG peer review conducted in 2003.

The licensee stated that the model that underwent the BWROG peer review was not an upgrade of the SSES Unit 1 and 2 IPE; instead, it was a new model based on thermal-hydraulic calculations for the current fuel type and current rated power. New event trees were developed based on the calculated accident progression and current EOPs. The BWROG peer review did not identify any significant “A” facts and observations (F&Os) (i.e., findings that are extremely important and necessary to address the technical adequacy of the PRA) for the SSES Unit 1 and 2 PRA, but it did identify a number of lesser significant F&Os. The licensee indicated that it incorporated into the revised SSES Unit 1 and 2 PRA model approximately half of the “B” F&Os (i.e., findings that are extremely important and necessary to address but that may be deferred until the next PRA update) and some of the “C” F&Os (i.e., findings considered desirable to maintain maximum flexibility in PRA application and consistency in the industry but that are not likely to significantly affect results or conclusions).

After performing a self-assessment using the guidance in RG 1.200, “An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities,” the licensee determined that it needed to address the remaining open “B” F&Os. The licensee judged other identified gaps as not having an impact on the CPPU evaluation. The licensee provided a summary of the 19 previously unresolved open “B” F&Os and their disposition for the CPPU application. The seven open items related to the Level II analyses were dispositioned by incorporating updated detailed Level II analysis into the models used for the CPPU risk evaluation. Another four open items were dispositioned by incorporating new data or events into the CPPU model. The licensee determined that five open items did not have to be resolved for this application because they would not have a significant impact on the results and insights (e.g., formalizing the PRA model update process, completing system notebooks, and including more preinitiator human errors). The licensee dispositioned the remaining three open items by performing specific sensitivity calculations. These open items involve the need to specifically model the loss of service water and loss of instrument air initiating events.

The licensee submitted the SSES Unit 1 and 2 IPEEE, which addressed external events, to the NRC on June 30, 1994, in response to Supplement 4 of GL 88-20. On April 27, 1999, the NRC issued an SE that concluded that the licensee adequately addressed high winds, floods, transportation, and other external events. The SE also indicated that, because of issues or concerns from the initial review, a more detailed review and site audit were necessary to determine whether the licensee’s seismic and fire analyses met the intent of Supplement 4 to GL 88-20. As a result of the more detailed review and site audit, the NRC staff concluded that all of the remaining seismic review issues had been resolved. Regarding the fire analysis, the NRC staff identified a potentially significant weakness with the licensee’s fire methodology used for quantifying the CDF. The licensee’s fire analysis assumed that the severity of a fire and the probability of fire suppression failure were independent. This assumption fails to take into account the possibility of damage occurring before effective suppression actually takes place. In response to NRC staff RAIs regarding the SSES Unit 1 and 2 IPEEE analyses, the licensee provided updated results for its fire analysis, including results that specifically address the potential weakness identified above by not taking credit for suppression actions. The NRC staff has relied upon this updated fire analysis in determining the potential impacts of the CPPU.

The quality of the licensee's PRA used to support a license application needs to be commensurate with the role the PRA results play in the utility's and NRC staff's decisionmaking process. It should also be commensurate with the degree of rigor needed to provide a valid technical basis for the NRC staff's decision. In this case, the licensee is not requesting relaxation of any deterministic requirements for the proposed CPPU, and the NRC staff's approval is based on the licensee meeting the current deterministic requirements, with the risk assessment providing confirmatory insights and ensuring that the CPPU creates no new vulnerabilities.

The NRC staff's evaluation of the licensee's submittal focused on the capability of the licensee's PRA and other risk evaluations (e.g., for external events) to analyze the risks stemming from pre- and post-CPPU plant operations and conditions. The NRC staff's evaluation did not involve an indepth review of the licensee's PRA; instead, it involved an evaluation of the information provided by the licensee in its submittal, as supplemented by its RAI responses; considered the review findings on the SSES Unit 1 and 2 IPE and IPEEE; reviewed the BWROG peer review open "B" F&Os and their dispositions for this application; considered the licensee's self-assessment using the NRC guidance in RG 1.200; and used the licensee's updated fire analysis results, including not crediting fire suppression. In performing its review, the NRC staff concurs with the licensee's assessment of the BWROG peer review open items for this application, including the consideration of the sensitivity calculation results to address the loss of service water and loss of instrument air initiating events.

Based on its evaluation, the NRC staff finds that the licensee has met the intent of RG 1.174 (Sections 2.2.3 and 2.5) and SRP Chapter 19.0 and that the SSES Unit 1 and 2 models used to support the risk evaluation for this application have sufficient scope, level of detail, and technical adequacy.

2.13.2.2 Internal Events

The licensee assessed the risk impacts from internal events resulting from the proposed CPPU by reviewing the changes in plant design and operations resulting from the proposed CPPU, mapping these changes onto appropriate PRA elements, modifying affected PRA elements, as needed, to capture the risk impacts of the proposed CPPU, and requantifying the SSES Unit 1 and 2 PRA to determine the CDF and LERF of the post-CPPU plant. As a result of the CPPU, the licensee estimated a 5 to 6 percent increase in the internal events CDF (from 1.76×10^{-6}/year to 1.86×10^{-6}/year for Unit 1 and from 1.74×10^{-6}/year to 1.84×10^{-6}/year for Unit 2)—an increase of about 1×10^{-7}/year for Unit 1 and 1×10^{-7}/year for Unit 2. The licensee estimated the increase in the internal events LERF to be less than 1 percent (from 1.72×10^{-7}/year to 1.73×10^{-7}/year for Unit 1 and from 1.72×10^{-7}/year to 1.72×10^{-7}/year)—an increase of approximately 8×10^{-10}/year for both units.

The licensee's assessments included evaluations of CPPU impacts on the following areas, as described in the subsections below:

- initiating event frequency
- component reliability
- operator response
- success criteria

2.13.2.2.1 Internal Initiating Event Frequencies

The licensee stated in its submittal that the CPPU is not expected to create any new initiating events or increase the frequency of any existing initiating events. However, the licensee will make a number of changes to the BOP equipment (e.g., replacing HP turbine and condensate pump impellers) and setpoint changes (e.g., MS SRV opening and closing setpoints). The licensee evaluated the capabilities of the systems and components that will need to run at higher capacities and stated that, as needed, components were being replaced or modified to improve their capability.

The licensee did recognize that extensive changes to plant equipment can result in an increase in system unavailability or failure rate during the initial testing and “break-in” period. Therefore, some short-term increase in such events can be expected. The licensee performed some sensitivity calculations to address the potential increase in risk during this break-in period. However, the licensee stated that steady-state condition equivalent to, or better than, current plant performance is expected to result.

In the case of transients, the licensee stated that the evaluation of the CPPU plant and procedural changes do not result in any new transient initiators or increase transient initiator frequencies. Sensitivity calculations were performed that increased the nonisolation transient initiator frequency to bound the various changes to the BOP side of the plant. In addition, since the units may not be able to remain at power following the trip of a single main FW pump under CPPU conditions, the nonisolation transient sensitivity calculation took this potential into account.

For the first sensitivity case, the licensee assumed that an additional turbine trip and an additional LOFW event is experienced in the first year following startup under CPPU conditions. The CPPU CDF for Unit 1 increased from 1.86×10^{-6}/year to 2.29×10^{-6}/year—an increase of 4.3×10^{-7}/year (23 percent). The CPPU CDF for Unit 2 increased from 1.84×10^{-6}/year to 2.26×10^{-6}/year—an increase of 4.2×10^{-7}/year (23 percent). For the second sensitivity case, the licensee assumed an additional MSIV closure event in the first year following startup under CPPU conditions. The CPPU CDF for Unit 1 increased from 1.86×10^{-6}/year to 2.19×10^{-6}/year—an increase of 3.3×10^{-7}/year (18 percent). The CPPU CDF for Unit 2 increased from 1.84×10^{-6}/year to 2.17×10^{-6}/year—an increase of 3.3×10^{-7}/year (18 percent). Considerably smaller increases are calculated for the LERF for each of these sensitivity cases; in the range of 2 to 3 percent.

The licensee does not expect a change in the LOOP initiating event frequency. Licensee analysis indicated that the existing offsite power system electrical equipment was adequate for operation with the CPPU-related electrical output. Based on the analysis and plant modifications/replacements, the licensee concluded that the CPPU will have no significant impact on grid stability.

The licensee did not identify any impact on LOCA frequencies resulting from the CPPU. However, the licensee did acknowledge that increased flow rates for the CPPU can cause increased piping erosion/corrosion rates, and sensitivity calculations were performed that conservatively doubled the LOCA initiating event frequencies for small-, medium-, and large-LOCA categories, as well as the internal flooding initiating event frequencies for FW. For the third sensitivity case, the Unit 1 CDF increased from 1.86×10^{-6}/year to 1.94×10^{-6}/year—an increase of 8×10^{-8}/year (4 percent). The CPPU CDF for Unit 2 increased from 1.84×10^{-6}/year to 1.92×10^{-6}/year—an increase of 8×10^{-8}/year (4 percent). The increase in LERF for this sensitivity case is about 10 to 11 percent.

No impacts on support system initiators were postulated to result from the CPPU. However, based on the BWROG peer review, the licensee incorporated into the SSES Unit 1 and 2 PRA instrument air and service water initiating event fault trees. The base and sensitivity calculations reflect this model enhancement.

To investigate the potential for synergistic effects between the individual sensitivity cases and to bound the calculated potential impact in the first year following startup at CPPU conditions, the licensee also performed a fourth combined sensitivity case that incorporated all the conditions of the individual sensitivity cases. The CPPU CDF for Unit 1 increased from 1.86×10^{-6}/year to 2.70×10^{-6}/year—an increase of 8.4×10^{-7}/year (45 percent). The CPPU LERF for Unit 1 increased from 1.73×10^{-7}/year to 2.01×10^{-7}/year—an increase of 2.8×10^{-8}/year (16 percent). The CPPU CDF for Unit 2 increased from 1.84×10^{-6}/year to 2.68×10^{-6}/year—an increase of 8.4×10^{-7}/year (46 percent). The CPPU LERF for Unit 2 increased from 1.72×10^{-7}/year to 2.01×10^{-7}/year—an increase of 2.9×10^{-8}/year (17 percent). These increases are consistent with the summation of the individual sensitivity calculation increases.

The NRC staff finds that it is reasonable to conclude that the internal initiating event frequencies will not change significantly, as long as the operating ranges or limits of the equipment are not exceeded. The NRC staff based this finding on the licensee properly implementing the equipment modifications and replacements it identified in its license amendment submittal. Furthermore, based on the licensee's sensitivity calculation, any short-term risk impact from break-in failures caused by the numerous BOP equipment changes is expected to be small. Finally, the NRC staff notes that any changes observed in the future in initiating event frequencies will be identified and tracked under the plant's existing performance monitoring programs and processes and will be reflected in future updates of the PRA, based on plant actual operating experience.

The NRC staff has not identified any issues associated with the licensee's evaluation of internal initiating event frequencies that would significantly alter the overall results or conclusions for this license amendment. Therefore, the NRC staff concludes that there are no issues with the evaluation of internal initiating event frequencies associated with the SSES Unit 1 and 2 internal events PRA that would rebut the presumption of adequate protection or warrant denial of this license amendment. The expectation is that initiating event frequencies will not change as a result of the CPPU.

2.13.2.2.2 Component Reliability

The licensee concluded in its submittal that the CPPU would not significantly impact the reliability of equipment. The majority of the hardware changes in support of the CPPU may be characterized as either replacement of components with enhancements or upgrade of existing components. The licensee described no planned operational modifications as part of the CPPU that involve operating equipment beyond design ratings.

The NRC staff finds that it is reasonable to conclude that equipment reliability will not significantly change, as long as the operating ranges or limits of the equipment are not exceeded. The NRC staff based this finding on the licensee properly implementing the equipment modifications and replacements it identified in its license amendment submittal. Furthermore, any short-term risk impact of the numerous BOP equipment changes resulting from break-in failures is expected to be small. Finally, the NRC staff notes that the licensee's component monitoring programs are being relied upon to maintain the current reliability of the equipment. The NRC staff finds it reasonable to conclude that there will not be a substantial impact on the reliability of these components, as long as the component monitoring programs are properly implemented and the licensee takes appropriate actions, including equipment modifications and/or replacement, based on the collected monitoring/trending data.

The NRC staff has not identified any issues associated with the licensee's evaluation of component reliability that would significantly alter the overall results or conclusions for this license amendment. Therefore, the NRC staff concludes that there are no issues with component reliabilities/failure rates modeled in the SSES Unit 1 and 2 internal events PRA that would rebut the presumption of adequate protection or warrant denial of this license amendment. The expectation is that component reliability will not experience a significant change as a result of the CPPU.

2.13.2.2.3 Success Criteria

The licensee stated in its submittal that it evaluated the system success criteria of the SSES Unit 1 and 2 internal events PRA, specifically considering the effects of the increased boiloff rate, the increased heat load to the suppression pool, and the increased containment pressures and temperatures. However, the licensee further stated that the changed in these parameters because of the CPPU are generally small. The licensee indicated that it performed thermal-hydraulic calculations using the MAAP computer code for the proposed CPPU conditions. Based on the SSES Unit 1 and 2 CPPU MAAP runs and GE CPPU task reports, the licensee concluded that no adverse changes were identified in the system success criteria for the SSES Unit 1 and 2 internal events PRA.

The licensee noted that timing issues are the only changes in the modeled success criteria that have been identified for the Level I and Level II PRA. The licensee acknowledged that the timings can impact the human error probabilities (HEPs) for operator actions, and this change has been factored into revised HEP values for CPPU conditions, as described in Section 2.13.2.2.4 of this SE.

The PRA success criteria for RPV makeup remain the same for the post-CPPU configuration. The licensee stated that both HP and LP injection systems have more than adequate flow margin for the post-CPPU configuration. CRD flow remains a viable RPV makeup source in the long term, but it is not credited in the near term as a makeup source for either the pre- or post-CPPU conditions because of the higher decay heat loads in the first 4 hours following an initiating event. The CRDS is credited as a viable source for extended HP makeup after 4 hours from the initiating event for both the pre- and post-CPPU conditions.

The licensee noted that no changes to DHR systems are necessary for the CPPU configuration and the blowdown loads would not quantitatively influence the PRA results.

The RPV pressure following failure to scram is expected to increase slightly, but the number of SRVs expected to lift remain the same. The SRV setpoints were not changed as a result of the CPPU; however, the base probability of a stuck-open relief valve (SORV) because of increased cycling was increased in the SSES Unit 1 and 2 PRA by 13.3 percent by using the conservative upper bound approach of increasing SORV probability by a factor equal to the increase in reactor power. The licensee also noted that the number of SRVs needed for RPV emergency depressurization remains unchanged from the pre-CPPU configuration.

The licensee noted a negligible impact on the Level II PRA safety functions and results and concluded that no changes to the success criteria have been identified with regard to the Level II containment evaluation.

The NRC staff finds that it is reasonable to expect that the system success criteria will not change significantly because of the CPPU. The NRC staff has not identified any issues associated with the licensee's evaluation of success criteria that would significantly alter the overall results or conclusions for this license amendment. Therefore, the NRC staff concludes that there are no issues with the success criteria associated with the SSES Unit 1 and 2 internal events PRA that would rebut the presumption of adequate protection or warrant denial of this license amendment. The expectation is that the CPPU will cause no significant change in system success criteria.

2.13.2.2.4 Operator Actions

The licensee stated in its submittal that the SSES Unit 1 and 2 risk profile is dependent on the operating crew actions for successful accident mitigation. The success of these actions is, in turn, dependent on a number of performance-shaping factors and that the performance-shaping factor that is principally influenced by the CPPU is the time available within which to detect, diagnose, and perform required actions. The higher power level results in reduced times available for some operator actions.

The licensee performed MAAP calculations for the pre- and post-CPPU configurations to determine the change in allowable operator action timing. The licensee evaluated the impact of the power-level increase for all operator actions included in the PRA model. The licensee's PRA model does not credit operator actions that are not explicitly incorporated into SSES Unit 1 and 2 plant procedures. The license stated that no plant changes were made that inhibited the performance of an existing operator action in the PRA. For those operator actions with long operator response times, the licensee concluded that changing from pre-CPPU to post-CPPU conditions has no impact on the associated HEPs. For operator actions that the licensee identified as having the potential to be significantly impacted by the CPPU, a detailed HRA was performed. This analysis was based on the caused-based approach described in EPRI TR-100259, "An Approach to the Analysis of Operator Actions in PRA," issued June 1992. The EPRI approached used Technique for Human Error Rate Prediction HEP data from NUREG/CR-1278, "Handbook of Human Reliability Analysis with Emphasis on Nuclear Power Plant Applications," and added Accident Sequence Evaluation Program (ASEP) time reliability correlation (TRC) HEPs when the response time was short (i.e., less than 1 hour). For actions that did not significantly impact the PRA results, values based on industry simulator data from Gertman and Blackman, "Human Reliability and Safety Analysis Data Handbook," issued 1994, were generally used. Table 2.13.a below presents the operator actions identified by the licensee as being impacted by the CPPU. Items in bold in the table have a Fussel-Vessely importance value greater than 0.005 or a risk achievement worth importance value greater than 2.0 based on the CPPU model results.

Table 2.13.a - Changes in Post-Initiator HEPs Caused by the CPPU for Unit 1(2)

Basic Event	Description	Pre-CPPU		Post-CPPU	
		Time (minutes)	HEP	Time (minutes)	HEP
1(2)37-N-N-CST_18-O	Operator fails to transfer water to CST	13	1.5E-2	11	2.3E-2
1(2)50-1(2)52RXLEVELCTRL-O	Operator fails to control reactor water level	15	1.0E-2	13	1.5E-2
1(2)51-N-N-F005_TR-3-O	Operator fails to start CS given autostart failure—(TR-3 sequences)	25	1.3E-2	22	1.7E-2
1(2)51-N-N-F005_TR-5-O	Operator fails to start CS given autostart failure—(TR-5 sequences)	17	3.0E-2	15	3.9E-2
1(2)52-N-N-RPVLVL_5-O	Operator fails to control RPV level	3	2.5E-1	2.5	3.0E-1
1(2)52-N-N-RPVLVL_20-O	Operator fails to control RPV level	18	6.1E-3	15	1.0E-2
1(2)53-N-N-SLCS5-O	Operator fails to initiate SLCS in ATWS	3.7	7.8E-2	NA	NA
1(2)53-N-N-SLCS7-O	Operator fails to initiate SLCS in ATWS	6	3.3E-2	5	4.5E-2
1(2)53-N-N-SLCS8-O	Operator fails to initiate SLCS in ATWS	7	2.5E-2	NA	NA
1(2)53-N-N-SLCS12-O	Operator fails to initiate SLCS in ATWS	11	1.2E-2	9.5	1.6E-2
1(2)56-N-N-MRI12-O	Operator fails to initiate MRI after ATWS	7	6.1E-2	6	8.3E-2
1(2)83-MAND-AT-O	Operator fails to initiate manual depressurization (ATWS)	4	6.4E-2	3.5	8.3E-2
1(2)83-MAND-NA-O	Operator fails to initiate manual depressurization (non-ATWS, transients, and small steam LOCA)	25	4.7E-4	22	7.6E-4

Basic Event	Description	Pre-CPPU		Post-CPPU	
		Time (minutes)	HEP	Time (minutes)	HEP
1(2)83-MAND-SO-O	Operator fails to initiate manual depressurization (non-ATWS, small liquid LOCA, and SORV)	9	1.2E-2	8	1.6E-2
1(2)83-N-N-ADS_INH_10-O	Operator fails to inhibit ADS during ATWS	9	3.6E-2	8	4.7E-2
1(2)83-N-N-ADS_INH_7-O	Operator fails to inhibit ADS during ATWS	6	8.3E-2	5	1.2E-1
1(2)CLPIA-O	Operator fails to control LP injection during ATWS	3.7	1.6E-1	3.3	2.3E-1
LOCA_M-O	Operator fails to manually start the RHR or CS pumps for a LOCA_M	14	4.5E-2	12.5	5.6E-2
LOCA_S-O	Operator fails to manually start the RHR or CS pumps for a LOCA_S	18	2.7E-2	16	3.4E-2
TRANS-O	Operator fails to manually start the RHR or CS pumps for a transient	16	3.4E-2	14	4.5E-2
Z-EARLY-RXLC-O [1(2)50-1(2)52RXLEVELCTRL-O & 013-N-N-EARLY-O]	Joint HEP—operator fails to align fire main or RHRSW and fails to control reactor water level	15	1.2E-3	13	1.8E-3
Z-IACIG-RXLC-O [1(2)50-1(2)52RXLEVELCTRL-O & 1(2)25-N-N-FXTIACIG-O]	Joint HEP—operator fails to crosstie IA and CIG and fails to control reactor water level	15	3.3E-2	13	3.4E-2
Z-RXLC-CVLOC-O [1(2)50-1(2)52RXLEVELCTRL-O & 1(2)59-CNTVNTLOCAL-O]	Joint HEP—operator fails to control reactor water level and vent containment locally	15	5.5E-4	13	8.2E-4

An additional operator action was included in the post-CPPU PRA model related to the manual operation of the newly installed manual isolation valve in the spray pond return path that provides an alternate means of preventing the overheating of the UHS if the existing spray pond bypass valve fails to close. The licensee also enhanced the ATWS portion of the PRA model and revised the operator actions related to the SLC to reflect the recently approved change to SLC pump operation. The SLC logic modification allows only one SLC pump to operate at a time, which is reflected in the post-CPPU model, resulting in some pre-CPPU operator actions not applying for post-CPPU conditions. The ATWS model enhancements also resulted in the identification of an additional operator action related to inhibiting the ADS that has a Fussel-Vessely importance value greater than 0.005.

In order to review the licensee's HRA approach, the NRC staff considered the guidance and insights provided in NUREG-1842, "Analysis of Human Reliability Analysis Methods Against Good Practices," issued September 2006. Since the CPPU is not a risk-informed application, the NRC staff did not have the benefit of detailed information that would allow the review of the licensee's HRA approach of identifying and modeling the operator actions in the SSES Unit 1 and 2 PRA or the context surrounding each of the modeled actions.

The NRC staff agrees with the licensee's conclusion that no new operator actions, beyond the addition of the manual operation of the newly installed manual isolation valve in the spray pond, need to be incorporated into the PRA to represent the proposed CPPU, based on the review of the equipment changes needed to implement the CPPU. This conclusion is consistent with those made by other licensees that have conducted risk assessments of EPUs.

Knowledge of the context surrounding each of the modeled operator actions (e.g., the sequences that are addressed and the additional equipment failures that have occurred) is important to ensure that the correct HEPs have been assigned. The NRC staff agrees with the licensee's conclusion that the main impact of the proposed CPPU on the postinitiator operator actions is the reduction in time available for the plant operators to detect, diagnose, and perform required actions. Therefore, any inadequacies or errors in the identification and modeling of operator actions or consideration of the context surrounding each operator action that may affect the assignment of performance shaping factors (other than available time) used to estimate the HEPs appear in both the pre- and post-CPPU models. Thus, they tend to cancel out (i.e., they should not noticeably affect the estimation of the change in risk resulting from the proposed CPPU, even though they may impact the estimation of the total risk at pre-CPPU or post-EPU conditions).

The licensee's use of thermal-hydraulic analyses and knowledge of equipment capacities (e.g., battery depletion time) to determine the change in the time available for diagnosis and decisionmaking for the postinitiator operator actions is consistent with good PRA practices. The NRC staff observes that the apparent small changes in the available times, and the corresponding changes in the postinitiator HEP values, should not be taken literally since the parameters and models used to obtain them are uncertain. However, the NRC staff believes that the licensee's analysis is adequate to conclude that the change in postinitiator HEP values because of the proposed CPPU is small.

The licensee's use of two HRA quantification methods (the EPRI caused-based approach and ASEP) for time-limited postinitiator operator actions is consistent with NUREG-1842. Specifically, NUREG-1842 states that the TRC used in the ASEP method is based on data sources with a validated range of about 60 minutes. In addition, NUREG-1842 indicates that the ASEP TRC should not be used in isolation to address the cognitive failure because other potentially important information (e.g., the performance shaping factors not addressed by the TRC) must also be adequately addressed. The NRC staff observes that many HRA practitioners simply pick an HRA quantification method in advance of conducting the PRA and apply it to all postinitiator events regardless of their associated available times for diagnosis and decisionmaking. From this perspective, the licensee's approach to estimating the HEPs of time-limited postinitiator operator actions appears conservative.

Based on the licensee's submitted information, the NRC staff finds that it is reasonable to expect that the main impact of the CPPU is to reduce the time available for some operator actions, which will increase the associated HEPs. However, these increased HEPs are not expected to create significant impacts, unless a number of critical operator actions cannot be performed at the increased power level. The NRC staff has not identified any issues associated with the licensee's evaluation of operator actions that would significantly alter the overall results or conclusions for this license amendment. Therefore, the NRC staff concludes that there are no issues with the operator actions evaluation associated with the SSES Unit 1 and 2 internal events PRA that would rebut the presumption of adequate protection or warrant denial of this license amendment.

2.13.2.2.5 Internal Events NRC Staff Findings

The NRC staff has not identified any issues associated with the licensee's evaluation of the risks related to internal events that would significantly alter the overall results or conclusions for this license amendment. Therefore, the NRC staff concludes that there are no issues with the internal events risk evaluation that would rebut the presumption of adequate protection or warrant denial of this license amendment. The expectation is that the risk impact from internal events resulting from the proposed CPPU will be very small, based on the licensee's current risk evaluations, including consideration of its combined sensitivity calculation.

2.13.2.3 External Events

This section addresses the licensee's review of external events, which includes seismic events, internal fires, and other external events.

2.13.2.3.1 Seismic Events

For the IPEEE seismic analysis, SSES Units 1 and 2 are categorized as a 0.3g focused-scope plant in accordance with NUREG-1407, "Procedural and submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities." The licensee performed the SSES Unit 1 and 2 seismic evaluation in its IPEEE using the EPRI SMA methodology described in EPRI NP-6041, Revision 1. Because the SMA is a deterministic evaluation process, the licensee did not quantify a seismic contribution to plant CDF.

Seismic Category I structures, except the diesel generator "E" building, were designed to a seismic acceleration level of 0.1g peak ground acceleration. The diesel generator "E" building, which is founded on soil, was designed to a seismic acceleration level of 0.15g peak ground acceleration. The licensee estimated in the SSES Unit 1 and 2 IPEEE that the plant seismic capacity, in terms of HCLPF value, to be 0.21g because of a low seismic capacity of certain components (i.e., an HPCI discharge valve and an RHR suppression pool inlet valve). However, the licensee stated in the IPEEE that these low-capacity components are either not strictly required for safe shutdown of the plant or their failures may be rectified through manual recovery actions. The licensee concluded that the plant HCLPF capacity met the review-level earthquake value of 0.3g.

To gauge the baseline seismic CDF value at SSES Units 1 and 2, the NRC staff used the approximation method described in a paper by Robert P. Kennedy, entitled “Overview of Methods for Seismic PRA and Margin Analysis Including Recent Innovations.” This approach uses the plant’s HCLPF value and the site’s seismic hazard curve, based on NUREG-1488, to derive an approximation of the magnitude of the risk associated with seismic events. The NRC staff’s independent simplistic calculation used the plant HCLPF value of 0.21g and the recommended logarithmic standard deviation of 0.4. Using these values, the seismic CDF for SSES Units 1 and 2 is estimated to be less than $2x10^{-5}$/year.

The licensee noted that no open seismic issues are associated with its IPEEE SMA. Furthermore, the licensee stated that the increased power level is not expected to affect equipment or structural response during a seismic event. Additional blowdown loads on the RPV and containment, given a coincident seismic event, are judged not to alter the results of the SMA. The licensee judged the decrease in time available for operator actions, and the associated increases in calculated HEPs, to have an insignificant impact on seismic-induced risk. Based on its evaluation, the licensee concluded that the CPPU does not affect the SSES Unit 1 and 2 IPEEE SMA results.

2.13.2.3.2 Fires

For the IPEEE fire analysis, SSES Units 1 and 2 performed a fire PRA following the general approach described in NUREG/CR-2300, “A Guide to the Performance of Probabilistic Risk Assessments for Nuclear Power Plants,” issued January 1983. As stated previously, the NRC staff identified a potentially significant weakness with the licensee’s fire methodology used for quantifying the CDF in the IPEEE. The licensee’s fire analysis assumed that the severity of a fire and the probability of fire suppression failure were independent. This assumption fails to take into account the possibility of damage occurring before effective suppression actually takes place. In response to NRC staff RAIs regarding the SSES Unit 1 and 2 IPEEE analyses, the licensee provided updated results for its fire analysis, which addresses the credit for CRD only after 4 hours into an event, consistent with the internal events PRA, and includes sensitivity study results that specifically address the potential weakness identified above by not taking credit for suppression actions. The revised fire analysis also used the latest cable and raceway database information to determine the equipment lost in each fire zone because of a large fire in that zone.

Given that several fire zones that were screened out in the IPEEE do not screen out in the revised fire analysis, the licensee developed new fire frequencies considering a large fire in each of these zones and had their CDFs calculated. These calculations did not credit BOP equipment since the cable and raceway database did not address the functionality of this equipment.

Table 2.13.b provides the licensee’s revised fire analysis results, including the results of two sensitivity studies—one only crediting manual suppression and the other not crediting any suppression.

Table 2.13.b - SSES Unit 1 and 2 Revised Fire Analysis CDF

Case	Base CDF	Only Manual Suppression Credit	No Suppression Credit
Pre-CPPU	9.24E-7/year	2.67E-6/year	2.67E-5/year
CPPU	9.24E-7/year	2.67E-6/year	2.67E-5/year
Delta	4.19E-10/year	-1.78E-9/year	-1.78E-8/year

In the base case, the fire risk increase from pre- to post-CPPU is negligibly small. Although it would be expected that the post-CPPU fire risk results would be greater than the pre-CPPU conditions for the sensitivity calculations as well, the CPPU-related modification involving the installation of a redundant spray pond bypass valve, which can be closed if the current motor-operated bypass valve fails to close, offsets the fire risk impact associated with the increased power level in these sensitivity calculations (i.e., the positive risk influences of the modification are more apparent when automatic suppression is not credited). The additional valve was added to the plant design to accommodate the CPPU spray pond thermal analysis, but it also influences the fire risk results involving the failure of a division of the RHR system, which occurs in some, but not all, of the 135 fire zones that contribute to the overall fire CDF. For the CPPU, both valves must fail to close for the flow to bypass the spray pond array, resulting in a lower CPPU fire CDF than the pre-CPPU fire CDF, depending on the amount of other equipment failed directly by the fire.

2.13.2.3.3 Other External Events

The SSES Unit 1 and 2 IPEEE addresses external events other than seismic and fires, including high winds/tornadoes, external floods, and transportation and nearby facility accidents. Consistent with the IPEEE guidance, the licensee reviewed the plant environs against regulatory requirements regarding these hazards and concluded that SSES Units 1 and 2 meet the applicable NRC SRP requirements and, therefore, have an acceptably low risk with respect to these hazards.

2.13.2.3.4 External Events NRC staff Findings

The NRC staff has not identified any issues associated with the licensee's evaluation of the risks related to external events that would significantly alter the overall results or conclusions for this license amendment. Therefore, the NRC staff concludes that there are no issues with the external events risk evaluation that would rebut the presumption of adequate protection or warrant denial of this license amendment. The expectation is that the risk impact from external events resulting from the proposed CPPU will be very small, based on the licensee's current risk evaluations, including consideration of its revised fire risk analyses without crediting fire suppression.

2.13.2.4 Shutdown Operations

The licensee stated that the effect of the CPPU on shutdown risk is similar to its effect on the at-power Level I PRA in that the increase in decay heat affects the shutdown risk. The primary impact of the CPPU on risk during shutdown operations is associated with the decrease in allowable operator action times in response to events. The licensee stated that the reductions are on the order of 10 percent. However, the licensee stated that these allowable operator action times to respond to loss of heat removal scenarios during shutdown operations are many hours long, and such small changes in response times result in negligible changes in HEPs.

However, the licensee further stated that the lower power operating conditions during shutdown allow for additional margin for mitigation systems and operator actions. The aspects of shutdown risk that the licensee identified as being impacted by CPPU conditions included greater decay heat generation, longer times to shutdown, longer times before alternate DHR systems can be used, shorter times to boiling, and shorter times for operator responses. All of these aspects basically result from the increased decay heat generation created by the CPPU.

The increased power level decreases the boildown time. However, because the reactor is already shut down, the boildown times are relatively long compared to the at-power PRA. The licensee stated that, at 1 day into an outage with the RPV level at the flange, the time to core uncovery for CPPU conditions is 8.0 hours compared to 9.1 hours pre-CPPU—about a 12-percent reduction. At 8 hours into an outage with the RV head still in place and the reactor depressurized, the time to core uncovery for CPPU conditions is about 3.8 hours compared to about 4.4 hours pre-CPPU—about a 13-percent reduction in time. These changes in timing are expected to have a negligible impact on operator responses and associated HEPs.

The increased decay heat loads associated with the CPPU do not affect the success criteria for the systems normally used to remove decay heat, but the licensee stated that the CPPU does impact the time when low-capacity DHR systems can be considered successful alternate DHR systems. The licensee stated that the reduction in time for alternate DHR system success minimally impacts shutdown risk.

Other success criteria are stated as being marginally impacted by the CPPU. The CPPU has a minor impact on shutdown RPV inventory makeup during loss of DHR scenarios in shutdown because of the low decay heat level. The heat load to the suppression pool during loss of DHR scenarios is also lower than at power because of the low decay heat level, such that the margins for the SPC capacity are adequate for CPPU conditions. The licensee stated that the impact of the CPPU on the success criteria for blowdown loads, RPV overpressure margin, and SRV actuation is negligible because of the low RPV pressure and low decay heat level during shutdown.

Shutdown Operations NRC Staff Findings

The NRC staff has not identified any issues associated with the licensee’s evaluation of shutdown risks that would significantly alter the overall results or conclusions for this license amendment. Therefore, the NRC staff concludes that there are no issues with the shutdown operations risk evaluation that would rebut the presumption of adequate protection or warrant denial of this license amendment. The expectation is that the impact on shutdown risk resulting from the proposed CPPU will be negligibly small, based on the licensee’s current shutdown risk management process.

2.13.3 Conclusion

The NRC staff finds that, for internal events, no new impacts are expected for initiating event frequencies, component reliability, or success criteria, but impacts are expected for a limited number of operator actions because of the decrease in available operator response times resulting from the increase in decay heat associated with the CPPU. The NRC staff finds that the risk increases related to these impacts under CPPU conditions are expected to be very small and within the acceptance guidelines of RG 1.174.

The NRC staff finds that the licensee has a process for managing plant risk during shutdown operations and that the risk impact related to the CPPU during these operations is expected to be negligibly small. The NRC staff also finds that the risk impacts from external events under CPPU conditions are expected to be very small and within the acceptance guidelines of RG 1.174.

The NRC staff has reviewed the licensee's assessment of the risk impacts associated with the implementation of the proposed CPPU and concludes that the licensee has adequately modeled and/or addressed the potential impacts. In addition, the NRC staff expects that any significant changes in plant performance following implementation of the proposed CPPU would be identified and tracked under the licensee's existing performance monitoring programs and processes and incorporated, as appropriate, into future SSES Unit 1 and 2 PRA model updates. The NRC staff further concludes that the results of the licensee's risk analysis indicate that the risks associated with the proposed CPPU are acceptable and do not create the special circumstances described in Appendix D to SRP Chapter 19. Therefore, the NRC staff finds the risk implications of the proposed CPPU acceptable.

3.0 FACILITY OPERATING LICENSE AND TECHNICAL SPECIFICATION CHANGES

To achieve the EPU, the licensee proposed the changes described below to the facility operating license and TSs for SSES Units 1 and 2.

3.1 Operating License Change

Under License Condition 2.C(1), the licensee proposed to change the maximum reactor core power level from 3489 MWt to 3952 MWt.

The licensee proposed to change the steady-state reactor core power level from 3489 MWt to 3952 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 finds this proposed change acceptable.

3.2 Technical Specification Changes

a. Technical Specification 1.1, "Definitions," Rated Thermal Power

The proposed change is applicable to both units. The licensee proposed to change the maximum value of RTP from 3489 MWt to 3952 MWt consistent with License Condition 2.C(1). 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 finds this proposed change acceptable.

b. Technical Specification 2.1.1, "Reactor Core Safety Limits" (Technical Specification 2.1.1.1)

The proposed change is applicable to both units. The required thermal power when reactor steam dome pressure is less than 785 psig or core flow is less than 10 million lbm/hour is being lowered from 25 percent of RTP to 23 percent of RTP. As discussed in Section 2.1 of the SSES Unit 1 and 2 PUSAR, the original plant operating licenses set this monitoring threshold at a typical value of 25 percent of RTP. For SSES Units 1 and 2, the fuel thermal monitoring threshold is established at 23 percent of CPPU RTP. A change in the fuel thermal monitoring threshold also requires a corresponding change to the TS reactor core SL for reduced pressure or low core flow. This reduction is based on a rescaling of the thermal limits monitoring threshold to require thermal limits monitoring at an average absolute bundle power level that is consistent with industry practice. As discussed in SE Section 2.8.1, the NRC staff finds that this rescaling will continue to ensure that the thermal limits will be monitored at times when, during normal operation and AOOs, the fuel thermal limits could be challenged. On this basis, the NRC staff finds the thermal limits monitoring threshold rescaling acceptable.

c. Technical Specification 3.2.1, "Average Planar Linear Heat Generation Rate (APLHGR)," (Applicability, Required Action B.1, Surveillance Requirement 3.2.1.1, 1st Frequency, Surveillance Requirement 3.2.1.1, 3rd Frequency)

The proposed change is applicable to both units. The licensee proposed to revise the applicability value, the required action value, and the first frequency of SR 3.2.1.1 (to verify that all average planar LHGRs are less than or equal to the limits specified in the COLR) from 25 percent of RTP to 23 percent of RTP. This reduction is based on the change in the core flow safety limit from 25 percent of RTP to 23 percent of RTP. The basis for this change is the same as discussed in SE Section 3.2.b above. Therefore, the NRC staff finds the proposed change acceptable.

The licensee also proposed to revise the value in the third frequency for SR 3.2.1.1 from 50 percent of RTP to 44 percent of RTP. As the licensee stated in the enclosure to Reference 1, the basis of the change is to maintain the value approximately unchanged in thermal power. At CLTP, 50 percent of RTP is equal to 1744.5 MWt. At the CPPU, 1744.5 MWt equals 44.14 percent of RTP. The use of 44 percent of RTP is slightly more conservative. The NRC staff finds this change acceptable as the proposed value is more conservative than the current value in terms of absolute thermal power.

d. Technical Specification 3.2.2, "Minimum Critical Power Ratio (MCPR)," (Applicability, Required Action B, Surveillance Requirement 3.2.2.1, 1st Frequency, Surveillance Requirement 3.2.2.1, 3rd Frequency)

The proposed change is applicable to both units. The licensee proposed to revise the applicability value, the required action value, and the first frequency of SR 3.2.2.1 (to verify all MCPRs are greater than or equal to the limits specified in the COLR) from 25 percent of RTP to 23 percent of RTP. This reduction is based on the change in the core flow safety limit from 25 percent of RTP to 23 percent of RTP. The basis for this change is the same as discussed in SE Section 3.2.b above. Therefore, the NRC staff finds the proposed change acceptable.

The licensee also proposed to revise the value in the third frequency for SR 3.2.2.1 from 50 percent RTP to 44 percent RTP. The basis for this change is the same as discussed in SE Section 3.2.c. above. Therefore, the NRC staff finds the proposed change acceptable.

e. Technical Specification 3.2.3, "Linear Heat Generation Rate (LHGR)" (Applicability, Required Action B, Surveillance Requirement 3.2.3.1, 1st Frequency, Surveillance Requirement 3.2.3.1, 3rd Frequency)

The proposed change is applicable to both units. The licensee proposed to revise the applicability value, the required action value, and the first frequency of SR 3.2.3.1 (to verify all LHGRs are less than or equal to the limits specified in the COLR) from 25 percent of RTP to 23 percent of RTP. This reduction is based on the change in the core flow safety limit from

25 percent of RTP to 23 percent of RTP. The basis for this change is the same as discussed in SE Section 3.2.b above. Therefore, the NRC staff finds the proposed change acceptable.

The licensee also proposed to revise the value in the third frequency for SR 3.2.3.1 from 50 percent of RTP to 44 percent of RTP. The basis for this change is the same as discussed in SE Section 3.2.c. above. Therefore, the NRC staff finds the proposed change acceptable.

f. Technical Specification 3.3.1.1, "RPS Instrumentation" (Required Action E.1)

The proposed change is applicable to both units. The licensee proposed to reduce the required thermal power value from less than 30 percent of RTP to less than 26 percent of RTP if the required actions A, B, or C are not met when one or more required RPS channels are not available or one or more functions with RPS trip capability are not maintained. A value of 26 percent of RTP for the CPPU (based on 3952 MWt) is sightly more conservative then the current 30 percent value based on the CLTP value of 3489 MWt. This change will be effective at 1027.5 MWt as compared to the previous value of 1046.7 MWt. The NRC staff finds this change acceptable as the proposed value is more conservative than the current value.

g. Technical Specification 3.3.1.1, "RPS Instrumentation" (Required Action J.1, Surveillance Requirement 3.3.1.1.3 and Associated Note)

The proposed change is applicable to both units. The TS required action and the TS SR value are being lowered from the current 25 percent of RTP to 23 percent of RTP. This reduction is based on the change in the core flow safety limit from 25 percent of RTP to 23 percent of RTP. The basis for this change is the same as discussed in SE Section 3.2.b. Therefore, the NRC staff finds the proposed change acceptable.

h. Technical Specification 3.3.1.1, RPS Instrumentation" (Surveillance Requirement 3.3.1.1.8)

The proposed change is applicable to both units. The licensee proposed changing the LPRM calibration frequency from 1000 megawatt days/metric ton (MWD/MT) to 2000 MWD/MT. The licensee noted that more frequent calibrations would be required because of the increase in power and neutron flux, which, in turn, would lead to more wear and tear of the TIP system and the time TIP-related primary containment isolation valves are open. In response to staff RAIs, the licensee in its June 1, 2007, letter (Reference 33) clarified that the higher uncertainty resulting from the longer calibration interval (4.3 percent for 2000 MWD/MT as compared to the previous value of 3.4 percent for 1000 MWD/MT) has been taken in to account in the SL analysis performed for the EPU conditions. To account for the 25 percent allowable surveillance extension, the SL analysis was based on 2500 effective full-power hours, according to the original power densities, which is equivalent to approximately 2500 MWD/MT. In its July 13, 2007, letter (Reference 34), the licensee provided additional information, but NRC staff found it insufficient to justify the acceptance of the higher uncertainty for the longer calibration interval. By letter dated August 3, 2007 (Reference 35), the licensee withdrew the proposed change to extend the calibration frequency from 1000 to 2000 MWD/MT because of the time needed to perform additional analyses and the schedule impact on the overall EPU approval. Therefore, this TS change will not be implemented as originally proposed in the October 11, 2006, EPU LAR from PPL.

i. Technical Specification 3.3.1.1, "RPS Instrumentation" (Surveillance Requirement 3.3.1.1.16)

The proposed change is applicable to both units. The licensee proposed changing the verification of the turbine stop valve—closure and turbine control valve fast closure, trip oil pressure—low functions not bypassed from 30 percent of RTP to 26 percent of RTP. As discussed in SE Section 3.2.f above, this change is more conservative then the current value in terms of absolute thermal power. Therefore, the NRC staff finds this TS change acceptable.

j. Technical Specification 3.3.1.1, "RPS Instrumentation" (Surveillance Requirement 3.3.1.1.19)

The proposed change is applicable to both units. The licensee proposed accepting the verification that the OPRM system is not bypassed when the APRM simulated power is greater than or equal to 25 percent and recirculating drive flow is less than or equal to the value equivalent to the core flow value defined in the COLR, in lieu of the current APRM simulated power value of greater than or equal to 30 percent. The licensee has installed a power range neutron monitoring system with OPRMs for SSES Units 1 and 2 to implement the BWROG LTS Option III. This system is designed to provide for an automatic scram for the reactor when power oscillations above the system setpoint are detected. The Option III trip is armed only when plant operation is within the Option III trip-enabled region. The Option III trip-enabled region is currently defined as the region on the power/flow map with power greater than or equal to 30 percent of OLTP and core flow less than or equal to 60 percent of rated core flow. For the CPPU, the Option III trip-enabled region is rescaled to maintain the same absolute power/flow region boundaries.

Because the rated core flow is not changed, the 60-percent core flow boundary is not rescaled. The 30 percent of the OLTP boundary translates to 25 percent of the CPPU value. Section 2.8.3 of this SE addresses the NRC staff's acceptance of the Framatome OPRM analysis. Based on the acceptability of OPRM analysis, this TS change is acceptable as the proposed value in terms of the absolute RTP remains unchanged.

k. Technical Specification 3.3.1.1, "RPS Instrumentation" (Table 3.3.1.1-1, Function 2.b)

The proposed change is applicable to both units. The licensee proposed to change the AV for simulated thermal power—high (for two-loop operation) value from less than or equal to 0.62W+64.2 percent of RTP to less than or equal to 0.55W+60.7 percent of RTP in Mode 1. The licensee submitted the value less than or equal to 0.62W+64.2 percent of RTP under a separate LAR (ARTS/MELLLA application dated November 18, 2005), and the NRC staff approved it via the SE issued on March 23, 2007 (ADAMS Accession No. ML070720675). In its letter dated June 1, 2007 (Reference 33), the licensee provided the basis and partial calculation in support of the requested change. GE setpoint methodology adjusts the AVs and the nominal trip setpoint by the same difference as the changes in the analytical levels (ALs). The licensee further clarified in its July 13, 2007, letter (Reference 34), that the NRC staff previously reviewed and accepted the GE setpoint methodology for this change under the ARTS/MELLLA licensing amendment request. Based on the clarifications provided and the prior acceptance of this change, the NRC staff finds the TS change acceptable.

l. Technical Specification 3.3.1.1, "RPS Instrumentation" (Table 3.3.1.1-1, Note (b))

The proposed change is applicable to both units. The licensee proposed to change the AV for simulated thermal power—high value from less than or equal to 0.62(W- ΔW)+64.2 percent of RTP to less than or equal to 0.55(W-ΔW)+60.7 percent of RTP in Mode 1 when reset for single-loop operation in accordance with LCO 3.4.1, “Recirculating Loops Operating.” This change is similar to the change explained under Section 3.2.k above except that it applies for single-loop operation. Acceptance of this change is based on the explanation provided under Section 3.2.k above.

m. Technical Specification 3.3.1.1, “RPS Instrumentation” (Table 3.3.1.1-1, Function 2.f)

The proposed change is applicable to both units. The licensee proposed to decrease the applicability for the OPRM trip function from greater than or equal to 25 percent to greater than or equal to 23 percent of RTP. This reduction is based on the change in the core flow safety limit from 25 percent of RTP to 23 percent of RTP. The basis for this change is the same as discussed in SE Section 3.2.b. Therefore, the NRC staff finds the proposed change acceptable.

n. Technical Specification 3.3.1.1, “RPS Instrumentation” (Table 3.3.1.1-1, Function 8, and Table 3.3.1.1-1, Function 9)

The proposed change is applicable to both units. The licensee proposed to revise the applicability value for the function to be active from 30 percent of RTP to 26 percent of RTP to maintain the RTP value the same as it was before the CPPU. As discussed in SE Section 3.2.f above, this change is more conservative than the current value in terms of absolute thermal power. Therefore, the NRC staff finds this TS change acceptable.

o. Technical Specification 3.3.2.2, “Feedwater—Main Turbine High Water Level Trip Instrumentation” (Applicability, Required Action C.1)

The proposed change is applicable to both units. The licensee proposed to change the RTP applicability value and the required action C.1 statement value from 25 percent of RTP to 23 percent of RTP to be consistent with the reduced thermal power. This reduction is based on the change in the core flow safety limit from 25 percent of RTP to 23 percent of RTP. The basis for this change is the same as discussed in SE Section 3.2.b. Therefore, the NRC staff finds the proposed change acceptable.

p. Technical Specification 3.3.4.1, “End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation” (Applicability, Required Action C.2, Surveillance Requirement 3.3.4.1.4)

The proposed change is applicable to both units. The licensee proposed to change the applicability value and the required action C.2 statement value from greater than or equal to 30 percent of RTP to greater than or equal to 26 percent of RTP. The licensee also proposed to change the TS setting for verifying turbine stop valve closure and turbine control valve fast closure, trip oil pressure low functions are not bypassed when the thermal power is greater than or equal to 26 percent of RTP as opposed to the current value of greater than or equal to 30 percent of RTP. This is to maintain the approximate reactor thermal power the same as it was before the CPPU. As addressed in 3.2.f above, 26 percent of the EPU value is slightly more conservative then the current 30-percent value in terms of thermal power. Therefore, the NRC staff finds the proposed changes acceptable.

q. Technical Specification 3.3.6.1, “Primary Containment Isolation Instrumentation” (Table 3.3.6.1-1, Function 1.c, Main Steamline Flow—High)

The proposed change is applicable to both units. The licensee proposed to change the MSL high flow AV from a differential pressure of 121 pounds per square inch differential (psid) to 179 psid related to the increase in steamflow because of the higher power. The current AV of 121 psid corresponds to an AL of 138 percent of the CLTP rated steamflow. The value of 138 percent resulted from an increase in rated steamflow caused by a reduction in measurement uncertainty associated with use of the leading edge flow meter (LEFM) technology for measuring FW flow rate. Before that change, the AL was 140 percent of the steamflow. For the CPPU, the AL, in percentage of steamflow, is restored to its prior value of 140 percent, and the licensee is not taking credit for the lower uncertainty associated with the use of LEFM technology. The restriction on the thermal power limit when the leading edge flowmeter is not available has been removed based on the change in TS 5.6.5.b. (see SE section 3.2.z).

To measure the increased steamflow for the CPPU, the flow instrumentation is being replaced with instrumentation capable of monitoring the increased MS flow. The AV and associated nominal trip setpoint were recalculated using the GE instrument setpoint methodology in NEDC-31336P-A. The revised setpoint calculations use the AL value of steamflow of 140 percent.

The licensee provided clarifications and excerpts from the steamflow differential pressure calculation performed by GE in its June 1, 2007, letter (Reference 33). In this letter, the licensee provided the calculated values along with the equations used in the calculation of the differential pressure for measuring steamflow. Adequate margins have been provided in the calculation between the AL, AV, AAF, AAL, and the nominal trip setpoint. Section 4.3 of the GE calculation includes an assumption regarding the accuracy of M&TE. In its July 13, 2007, letter (Reference 34), the licensee stated that, "The actual accuracy of the M&TE equipment used for calibration will be equal to or better than the M&TE accuracy assumed in the calculation." The PPL standard for M&TE accuracy is to use M&TE instruments that are at least four times more accurate than the instrument being calibrated. Thus, for the MSL differential pressure indicating switches with an accuracy of ±3 percent, the M&TE would have an accuracy of ±0.75 percent or better. Typically, for these instruments, a Heise gauge that has an accuracy of ±0.1 percent full scale is used. Thus, for a 200 psi full-scale range, the accuracy would be ±0.2 psi, well within the ±2.2 psi assumed by GE in the setpoint calculation. Using the upper range of differential pressure as 200 psi (full-scale range) and the M&TE instrument accuracy as ±0.75 percent, the M&TE error would be ±1.5 psi, which is below the ±2.2 psi assumed in the calculation. Based on these clarifications, the revised setpoint of 179 psid is acceptable to the NRC staff.

r. Technical Specification 3.4.2, "Jet Pumps" (Surveillance Requirement 3.4.2.1, Note 2)

The proposed change is applicable to both units. The TS SR Note 2 value is being lowered from 25 percent of RTP to 23 percent of RTP. This reduction is based on the change in the core flow safety limit from 25 percent of RTP to 23 percent of RTP. The basis for this change is the same as discussed in SE Section 3.2.b. Therefore, the NRC staff finds the proposed change acceptable.

s. Technical Specification 3.4.3, "Safety/Relief Valves (S/RVs)," (Limiting Condition for Operation 3.4.3)

The proposed change is applicable to both units. The licensee proposed to revise the LCO for TS 3.4.3 to require 14 SRVs to be operable versus 12 SRVs. Based on the discussion in SE Section 2.8.4.2, the NRC staff finds the proposed changes acceptable as the licensee has demonstrated an acceptable analysis of the plant response to overpressure conditions consistent with the proposed TS.

t. Technical Specification 3.4.10, “RCS Pressure and Temperature (P/T) Limits,” (Surveillance Requirement 3.4.10.5, Note a, Surveillance Requirement 3.4.10.6, Note a)

The proposed change is applicable to both units. The licensee proposed to revise the TS SR value from the current 30 percent of RTP to 27 percent of RTP. As the licensee stated in the enclosure to Reference 1, this proposal would maintain the value approximately unchanged in thermal power. At CLTP, 30 percent of RTP equals 1046.7 MWt. At the CPPU, 1046.7 MWt equals 26.49 percent of RTP. The use of 27.0 percent of RTP is slightly more conservative. The NRC staff finds this change acceptable as the proposed value is more conservative than the current value in terms of absolute thermal power.

u. Technical Specification 3.6.1.3, “Primary Containment Isolation Valves (PCIVs),” (Surveillance Requirement 3.6.1.3.12)

The proposed change is applicable to both units. The licensee proposed to revise the first test pressure for MSIV leakage rate testing from 22.5 psig to 24.3 psig. As discussed in SE Section 2.6.1, the NRC staff finds this acceptable since P_a, the calculated peak containment internal pressure related to the design-basis LOCA for the EPU, is determined with acceptable methods and assumptions.

v. Technical Specification 3.7.1, “Residual Heat Removal Service Water (RHRSW) System and the Ultimate Heat Sink (UHS),” (Condition A, Surveillance Requirements 3.7.1.4, 3.7.1.5, 3.7.1.6, and 3.7.1.7, Tables 3.7.1-1, 3.7.1-2, and 3.7.1-3)

The proposed change is applicable to both units. The licensee proposed to add entry conditions for inoperable valves in a new Table 3.7.1-3 and entry conditions for the combination of valves inoperable in Tables 3.7.1-1, 3.7.1-2, and 3.7.1-3 (valves in the same return header). The licensee also proposed to add SRs to periodically stroke the small loop spray array valves and the spray loop bypass manual valves with a frequency of 92 days. Based on the discussion in SE Section 2.5.3.4, the NRC staff finds the proposed changes acceptable.

w. Technical Specification 3.7.6, “Main Turbine Bypass System” (Applicability, Required Action B.1)

The proposed change is applicable to both units. The licensee proposed to revises the value of 25 percent of RTP to 23 percent of RTP. The basis for this change is the same as discussed in SE Section 3.2.b. Therefore, the NRC staff finds the proposed change acceptable.

x. Technical Specification 3.7.8, “Main Turbine Pressure Regulation System”

The proposed change is applicable to both units. The licensee proposed to add a new TS requiring that both main turbine pressure regulators be operable or that the MCPR and LHGR thermal limits as specified in the COLR be applied for an inoperable main turbine pressure regulator. At CPPU conditions, failure of a pressure regulator with the redundant pressure regulator out of service is a limiting event. The new TS requires either prompt restoration of the inoperable pressure regulator to operable status or the appropriate thermal limits specified in the COLR for the condition must be applied to ensure that SLs are not exceeded. On this basis, the NRC staff finds the proposed TS acceptable.

y. Technical Specification 5.5.12, "Primary Containment Leakage Rate Testing Program"

The proposed change is applicable to both units. The licensee proposed to revise the value of the peak calculated containment internal pressure for the design-basis LOCA, P_a, from 45.0 psig to 48.6 psig. As discussed in SE Section 2.6.1, the NRC staff finds this acceptable since P_a is determined with acceptable methods and assumptions.

z. Technical Specification 5.6.5, "Core Operating Limits Report (COLR)," (Technical Specification 5.6.5.b, Listing of Approved Analytical Methods, Items 10 and 11 (Unit 1) and Items 17 and 18 (Unit 2))

The proposed change is applicable to both units. The licensee proposed to remove the restriction on the core thermal power level when FW flow measurements from the LEFM system are not available. As stated in the licensee's enclosure to Reference 1, use of the LEFM system permitted a reduction in the uncertainty associated with ALs used to determine the core operating limits from 2 percent of RTP to 0.4 percent of RTP and allowed operating at a higher thermal power level. TS 5.6.5.b restricts the core thermal power level to a reduced power level when the LEFM system is not available such that a 2-percent margin between the operating power level and the power level used in the analyses is maintained. For the CPPU, the analytical methods for determining the core operating limits use 2-percent uncertainty without regard for the improved FW flow measurement accuracy provided by the LEFM system. Consequently, the restriction on the core thermal power level when FW flow measurements from the LEFM system are not available is no longer appropriate. On this basis, the NRC staff finds this proposed TS change acceptable.

The licensee also proposed to delete approved analytical methods associated with the LEFM system, including (1) Caldon, Inc., "Topical Report: Improving Thermal Power Accuracy and Plant Safety while increasing Operating Power Level Using the LEFM System," and (2) Caldon, Inc., "Supplemental to Topical Report ER-80P." These methods are no longer needed with the restoration of the 2-percent margin between the analyses and the operating power level. On this basis, the NRC staff finds this proposed TS change acceptable.

3.3 Technical Specification Bases Changes

The licensee has also proposed changes to the TS bases for clarity and to conform to the changes being made to the associated TSs. The NRC staff has no objections to these changes.

3.4 License Conditions

3.4.1 Potential Adverse Flow Effects

The NRC staff informed PPL that it is considering license conditions and regulatory commitments for monitoring, evaluating, and taking prompt action in response to potential adverse flow effects as a result of EPU operation on plant SSCs (including verifying continued structural integrity of the steam dryer) and for interacting with the NRC staff during power ascension for SSES Units 1 and 2, if an EPU license amendment is approved. The NRC staff further informed PPL that it considers license conditions and regulatory commitments similar to those placed on the Vermont Yankee nuclear power plant in the EPU license amendment issued on March 2, 2006, to also be appropriate for an SSES Unit 1 and 2 EPU license amendment. Therefore, the NRC staff requested PPL to propose license conditions and/or regulatory commitments and indicate where those license conditions and regulatory commitments should be modified to reflect power ascension plans for SSES Units 1 and 2.

In PLA-6242 (Reference 38), PPL proposed separate licensing conditions for SSES Units 1 and 2. The licensee modeled these conditions on those placed on the Vermont Yankee EPU license amendment issued March 2, 2006. Because of the power ascension plan to collect instrumented dryer data up to 107 percent of 3489 MWt on Unit 1 (and not on Unit 2), unit-specific license conditions are appropriate.

3.4.1.1 <u>SSES Unit 1 License Conditions—Potential Adverse Flow Effects</u>

These license conditions provide for monitoring, evaluating, and taking prompt action in response to potential adverse flow effects as a result of power uprate operation on plant SSCs (including verifying the continued structural integrity of the steam dryer).

3.4.1.1.1 The following requirements are placed on operation of the PPL Susquehanna, LLC, facility above the CLTP level of 3489 MWt:

(a) At each 3.5-percent power ascension step up to 107 percent of 3489 MWt, PPL shall obtain dryer strain gauge data and compare it to the acceptance criteria during power ascension above 3489 MWt. At each 3.5-percent power ascension step above 107 percent of 3489 MWt, PPL shall obtain MSL strain gauge data and compare it to the limit curve for the dryer strains during power ascension.

(b) PPL shall monitor the MSL strain gauges during power ascension testing above 3489 MWt for increasing pressure fluctuations in the steamlines.

(c) PPL shall hold the facility at each 3.5-percent ascension step to collect data from License Condition 3.4.1.1.1.a and conduct plant inspections and walkdowns, then evaluate steam dryer performance based on the data; shall provide the evaluation by facsimile or electronic transmission to the NRC project manager upon completion of the evaluation; and shall not increase power above each hold point until 96 hours after the NRC project manager confirms receipt of the transmission.

(d) If any acceptance criterion for steam dryer strains at each 3.5-percent power ascension step up to 107 percent of 3489 MWt or frequency peak from the MSL strain gauge data exceeds the limit curve for the MSL strains above 107 percent of 3489 MWt, PPL shall return the facility to a power level at which the acceptance criterion is not exceeded. PPL shall resolve the discrepancy, document the continued structural integrity of the steam dryer, and provide that documentation by facsimile or electronic transmission to the NRC project manager before further increasing reactor power.

(e) In addition to evaluating the dryer instrumentation data and MSL strain gauge data, PPL shall monitor RPV water-level instrumentation and MSL piping accelerometers during power ascension above 3489 MWt. If resonance frequencies are identified as increasing above nominal levels in proportion to instrumentation data, PPL shall stop power ascension, document the continued structural integrity of the steam dryer, and provide that documentation by facsmilie or electronic transmission to the NRC project manager before further increasing reactor power.

(f) Following CPPU startup testing, PPL shall resolve any discrepancies in the steam dryer analysis and provide that resolution by facsimile or electronic transmission to the NRC project manager. If the discrepancies are not resolved within 90 days of identification, PPL shall return the facility to a power level at which the discrepancy does not exist.

3.4.1.1.2 PPL shall implement the following actions:

(a) PPL shall provide to the NRC the as-built dryer stress reconciliation and load limit curves 45 days before operation above 3489 MWt.

(b) After the dryer stress analysis is benchmarked to the Unit 1 startup test data (Unit 1 data taken up to 107 percent of 3489 MWt), PPL shall provide the benchmark results and updated MSL limit curves to the NRC 90 days before operation above 107 percent of 3489 MWt.

(c) In the event that acoustic signals are identified that challenge the limit curve during power ascension above 107 percent, PPL shall evaluate dryer loads and reestablish the acceptance criteria based on the new data and shall perform an assessment of ACM uncertainty at the acoustic signal frequency.

(d) After reaching 107 percent of CLTP, PPL shall obtain measurements from the steam dryer instrumentation and establish the steam dryer FIV load fatigue margin for the facility, update the dryer stress report, and reestablish the limit curve with the updated ACM load definition and revised instrument uncertainty, which will be provided to the NRC staff.

(e) During power ascension above 107 percent of CLTP, if an engineering evaluation is required because a Level 1 acceptance criterion is exceeded, PPL shall perform the structural analysis to address frequency uncertainties up to ±10 percent and ensure that peak responses that fall within this uncertainty band are addressed.

(f) PPL shall revise the post-CPPU monitoring and inspection program to reflect long-term monitoring of plant parameters potentially indicative of steam dryer failure; to reflect consistency of the facility's steam dryer inspection program with GE Service Information Letter (SIL) 644, "BWR/3 Steam Dryer Failure," Revision 2, and to identify the NRC project manager for the facility as the point of contact for providing PATP information during power ascension.

(g) PPL shall submit CPPU steam dryer reports to the NRC following completion of testing of Unit 1 power ascension to 107 percent of CLTP and 114 percent of CLTP. Each of these two written reports will include evaluations or corrective actions that were required to ensure steam dryer structural integrity. Additionally, they will include relevant data collected at each power step, comparisons to performance criteria (design predictions), and evaluations performed in conjunction with steam dryer structural integrity monitoring.

(h) PPL shall submit to the NRC the portions of the CPPU startup test procedure related to FIV, including methodology for updating the limit curve, before initial power ascension above 3489 MWt.

3.4.1.1.3 PPL shall prepare the CPPU startup test procedure to include the following and provide the related CPPU startup test procedure sections by facsimile or electronic transmission to the NRC project manager before increasing power above 3489 MWt:

(a) steam dryer strain gauge acceptance criteria to be used up to 107 percent of CLTP and the MSL strain gauge limit curves to be applied for evaluating steam dryer performance above 107 percent of CLTP

(b) specific hold points and their duration during CPPU power ascension

(c) activities to be accomplished during hold points

(d) plant parameters to be monitored

(e) inspections and walkdowns to be conducted for steam, FW, and condensate systems and components during the hold points

(f) methods to be used to trend plant parameters

(g) acceptance criteria for monitoring and trending plant parameters and conducting the walkdowns and inspections

(h) actions to be taken if acceptance criteria are not satisfied

(i) verification of the completion of commitments and planned actions specified in the PPL application and all supplements to the application in support of the CPPU LAR pertaining to the steam dryer before power increase above 3489 MWt

3.4.1.1.4 PPL shall not make the following key attributes of the PATP less restrictive without prior NRC approval:

(a) test plateau increments of approximately 3.5 percent of 3489 MWt during initial power ascension testing above 3489 MWt

(b) Level 1 performance criteria

(c) the methodology for establishing the stress criteria used for the Level 1 and Level 2 performance criteria

Changes to other aspects of the PATP may be made in accordance with the guidance of Nuclear Energy Institute (NEI) 99-04, "Guidelines for Managing NRC Commitments," issued July 1999.

3.4.1.1.5 During each scheduled refueling outage until at least two full operating cycles at full CPPU conditions have been achieved, PPL shall conduct a visual inspection of all accessible, susceptible locations of the steam dryer in accordance with BWRVIP-139 and GE inspection guidelines.

3.4.1.1.6 PPL shall report the results of the visual inspections of the steam dryer to the NRC staff within 60 days following startup. The licensee shall submit the results of the PATP to the NRC staff in a report within 60 days following the completion of all CPPU power ascension testing.

3.4.1.1.7 This license condition shall expire upon satisfaction of the requirements in paragraphs 3.4.1.1.5 and 3.4.1.1.6 provided that a visual inspection of the steam dryer does not reveal any new unacceptable flaw or unacceptable flaw growth that is caused by fatigue.

3.4.1.2 SSES Unit 2 License Conditions—Potential Adverse Flow Effects

These license conditions provide for monitoring, evaluating, and taking prompt action in response to potential adverse flow effects as a result of power uprate operation on plant SSCs (including verifying the continued structural integrity of the steam dryer).

3.4.1.2.1 The following requirements are placed on operation of the PPL Susquehanna, LLC, facility above the CLTP level of 3489 MWt:

(a) At each 3.5-percent power ascension step, PPL shall obtain MSL strain gauge data and compare it to the limit curve for the dryer strains during power ascension.

(b) PPL shall monitor the MSL strain gauges during power ascension above 3489 MWt for increasing pressure fluctuations in the steamlines.

(c) PPL shall hold the facility at each 3.5-percent ascension step to collect data from License Condition 1.a and conduct plant inspections and walkdowns, then evaluate steam dryer performance based on the data; shall provide the evaluation by facsimile or electronic transmission to the NRC project manager upon completion of the evaluation; and shall not increase power above each hold point until 96 hours after the NRC project manager confirms receipt of transmission.

(d) If any frequency peak from the MSL strain gauge data exceeds the limit curve for dryer strains above 3489 MWt, PPL shall return the facility to a power level at which the acceptance criterion is not exceeded. PPL shall resolve the discrepancy, document the continued structural integrity of the steam dryer, and provide that documentation by facsimile or electronic transmission to the NRC project manager before further increasing reactor power.

(e) In addition to evaluating the dryer strain and MSL strain gauge data, PPL shall monitor RPV water-level instrumentation or MSL piping accelerometers during power ascension above 3489 MWt. If resonance frequencies are identified as increasing above nominal levels in proportion to instrumentation data, PPL shall stop power ascension, document the continued structural integrity of the steam dryer, and provide that documentation by facsimile or electronic transmission to the NRC project manager before further increasing reactor power.

(f) Following CPPU startup testing, PPL shall resolve the discrepancies in the steam dryer analysis and provide that resolution by facsimile or electronic transmission to the NRC project manager. If the discrepancies are not resolved within 90 days of identification, PPL shall return the facility to a power level at which the discrepancy does not exist.

3.4.1.2.2 PPL shall implement the following actions:

(a) PPL shall provide to the NRC the as-built dryer stress analysis and load limit curves 45 days before operation above 3489 MWt.

(b) After the dryer stress analysis is benchmarked to the Unit 1 startup test data (Unit 1 data taken up to 107 percent of 3489 MWt), PPL shall provide the benchmarked PATP and MSL limit curves to the NRC 90 days before operation above 107 percent of 3489 MWt.

(c) In the event that acoustic signals are identified that challenge the limit curves during power ascension above 3489 MWt, PPL shall evaluate dryer loads and reestablish the acceptance criteria based on the new data and shall perform an assessment of ACM uncertainty at the acoustic signal frequency.

(d) After reaching full CPPU, PPL shall obtain measurements from the MSL strain gauges and establish the steam dryer FIV load fatigue margin for the facility, update the dryer stress report, if required, and reestablish the limit curve with the updated ACM load definition and revised instrument uncertainty, which will be provided to the NRC staff.

(e) During power ascension above 3489 MWt, if an engineering evaluation is required because a Level 1 acceptance criterion is exceeded, PPL shall perform the structural analysis to address frequency uncertainties up to ±10 percent and ensure that peak responses that fall within this uncertainty band are addressed.

(f) PPL shall revise the post-CPPU monitoring and inspection program to reflect long-term monitoring of plant parameters potentially indicative of steam dryer failure; to reflect consistency of the facility's steam dryer inspection program with GE SIL 644, "BWR/3 Steam Dryer Failure," Revision 2; and to identify the NRC project manager for the facility as the point of contact for providing PATP information during power ascension.

(g) PPL shall submit a CPPU steam dryer report to the NRC following completion of Unit 2 ascension to 114 percent of CLTP. The report shall include evaluations or corrective actions that were required to ensure steam dryer structural integrity. Additionally, it shall include relevant data collected at each power step, comparisons to performance criteria (design predictions), and evaluations performed in conjunction with steam dryer structural integrity monitoring.

(h) PPL shall submit to the NRC the portions of the CPPU startup test procedure related to FIV, including methodology for updating the limit curve, before initial power ascension above 3489 MWt.

3.4.1.2.3 PPL shall prepare the CPPU startup test procedure to include the following and provide the related CPPU startup test procedure sections by facsimile or electronic transmission to the NRC project manager before increasing power above 3489 MWt:

(a) MSL strain gauge limit curves to be used up to 114 percent of CLTP

(b) specific hold points and their duration during CPPU power ascension

(c) activities to be accomplished during hold points

(d) plant parameters to be monitored

(e) inspections and walkdowns to be conducted for steam, FW, and condensate systems and components during the hold points

(f) methods to be used to trend plant parameters

(g) acceptance criteria for monitoring and trending plant parameters and conducting the walkdowns and inspections

(h) actions to be taken if acceptance criteria are not satisfied

(i) verification of the completion of commitments and planned actions specified in the PPL application and all supplements to the application in support of the CPPU LAR pertaining to the steam dryer before power increase above 3489 MWt

3.4.1.2.4 The following key attributes of the PATP shall not be made less restrictive without prior NRC approval:

(a) test plateau increments of approximately 3.5 percent of 3489 MWt during initial power ascension testing above 3489 MWt

(b) Level 1 performance criteria

(c) the methodology for establishing the stress criteria used for the Level 1 and Level 2 performance criteria

Changes to other aspects of the PATP may be made in accordance with the guidance of NEI 99-04, “"Guidelines for Managing NRC Commitments," issued July 1999.

3.4.1.2.5 During the first two scheduled refueling outages after reaching full CPPU conditions, PPL shall conduct a visual inspection all accessible, susceptible locations of the steam dryer in accordance with BWRVIP-139 and GE inspection guidelines.

3.4.1.2.6 PPL shall report the results of the visual inspections of the steam dryer to the NRC staff within 60 days following startup. PPL shall submit the results of the PATP to the NRC staff in a report within 60 days following the completion of all CPPU power ascension testing.

3.4.1.2.7 This license condition shall expire upon satisfaction of the requirements in paragraphs 3.4.1.2.5 and 3.4.1.2.6 provided that a visual inspection of the steam dryer does not reveal any new unacceptable flaw or unacceptable flaw growth that is caused by fatigue.

3.4.2 Transient Testing

SE Section 2.5.4.4 discusses the license conditions described below.

3.4.2.1

PPL will demonstrate through performance of transient testing on each SSES unit that the loss of one condensate pump will not result in a complete loss of reactor FW. The test shall be performed on each unit during the unit's CPPU power ascension test program within 336 hours of achieving and before exceeding a nominal power level of 3733 MWt with FW and condensate flow rates stabilized. PPL shall confirm that the plant response to the transient is as expected in accordance with the acceptance criteria that are established. If a loss of all reactor FW occurs as a result of the test, the test failure shall be addressed in accordance with corrective action program requirements and the provisions of the power ascension test program before continued operation of the SSES unit above 3489 MWt.

3.4.2.2

Unless the NRC issues a letter notifying the licensee that the tests specified by License Condition 3.4.2.1 adequately demonstrate that a single condensate pump trip will not result in a loss of all FW while operating at the full CPPU power level of 3952 MWt, PPL shall perform the transient test on either SSES unit (whichever unit is first to achieve the following specified operating conditions) specified by License Condition 3.4.2.1 during the power ascension test program while operating at 3872 MWt to 3952 MWt (98 percent to 100 percent of the full CPPU power level) with FW and condensate flow rates stabilized. The test shall be performed within 90 days of operating at greater than 3733 MWt and within 336 hours of achieving a nominal power level of 3872 MWt with FW and condensate flow rates stabilized. PPL will demonstrate through performance of transient testing on either SSES Unit 1 or Unit 2 (whichever unit is first to achieve the specified conditions) that the loss of one condensate pump will not result in a complete loss of reactor FW. PPL shall confirm that the plant response to the transient is as expected in accordance with the acceptance criteria that are established. If a loss of all FW occurs as a result of the test, the test failure shall be addressed in accordance with corrective action program requirements and the provisions of the power ascension test program before continued operation of either SSES unit above 3733 MWt.

3.4.3 Neutronic Methods

3.4.3.1

An OPRM amplitude setpoint penalty will be applied to account for a reduction in thermal neutrons around the LPRM detectors caused by transients that increase voiding. This penalty will reduce the OPRM scram setpoint according to the methodology described in Response No. 3 of PPL letter, PLA-6306, dated November 30, 2007. This penalty will be applied until NRC evaluation determines that a penalty to account for this phenomenon is not warranted.

3.4.3.2

For SSES SLMCPR analyses, a conservatively adjusted pin power distribution uncertainty and bundle power correlation coefficient will be applied as stated in Response No. 4 of PPL letter, PLA-6306, dated November 30, 2007, when performing the analyses in accordance with ANF-524(P)(A), "Advanced Nuclear Fuels Corporation Critical Power Methodology for Boiling Water Reactors," using the uncertainty parameters associated with EMF-2158(P)(A) "Siemens Power Corporation Methodology for Boiling Water Reactors: Evaluation and Validation of CASMO-4/MICROBURN-B2."

3.4.4 Containment Operability for EPU

PPL shall ensure that the CPPU containment analysis is consistent with the SSES 1 and 2 operating and emergency procedures. Prior to operation above CLTP, PPL shall notify the NRC project manager that all appropriate actions have been completed.

4.0 REGULATORY COMMITMENTS

The licensee has made the following regulatory commitments, which have been or will be completed before or concurrent with the EPU amendment implementation or as noted in the individual commitments as "scheduled completion":

(1) (PLA-6128-1) Submit supplemental information to the NRC that summarizes proposed steam dryer modifications. (Completed by letter dated December 4, 2006, in which PPL stated that it will replace the existing SSES Unit 1 and 2 steam dryers with an improved design and provided associated supplemental information.)

(2) (PLA-6128-2) Submit supplemental information to the NRC that provides the results of the final finite element analysis at 120 percent of OLTP based on the final dryer structural configuration. (Completed by letter dated December 4, 2006, in which PPL stated that it will replace the existing SSES Unit 1 and 2 steam dryers with an improved design and provided associated supplemental information; this information was supplemented by letter dated July 6, 2007.)

(3) (PLA-6128-3) Submit supplemental information to the NRC that provides ASME load combination tables based on the 120 percent of OLTP condition. (Completed by letter dated December 26, 2006, as supplemented by letter dated July 6, 2007.)

(4) (PLA-6128-4) Submit supplemental information to the NRC that describes the steam dryer power ascension test plan. (Completed by letters dated December 26, 2006; April 27, July 7, and July, 31, 2007; see Section 3.4 above.)

(5) (PLA-6225-1) Enhanced visual testing (EVT-1) of the top guide grid beams will be performed in accordance with GE SIL 554, "Top Guide Cracking," following the sample selection and inspection frequency of BWRVIP-47 for CRD guide tubes. That is, inspections will be performed on 10 percent of the total population of cells within 12 years and on 5 percent of the population within 6 years. The sample locations selected for examination will be in areas that are exposed to the highest fluence. This inspection plan will be implemented beginning with the refueling outage following EPU operation. It will be implemented until an NRC-approved resolution is developed in accordance with the

BWRVIP and implemented at SSES Units 1 and 2. (Completion is scheduled to begin with the refueling outage following EPU operation.)

(6) (PLA-6315-1) Verified stress tables for the final as-built dryer will be provided to NRC by January 09, 2008 demonstrating that the maximum stress intensities in the replacement steam dryer are lower than the maximum stress intensity reported in Reference [70] and thus would satisfy the licensing basis ASME Code fatigue limit of 13,600 psi. (Completed by letter dated January 9, 2008.)

(7) (PLA-6315-2) The complete verified stress report (including the results of all Flow Induced Vibration (FIV) and ASME load case analyses) will be provided to NRC by February 04, 2008. This will also serve to satisfy the currently proposed License Condition to submit the report forty-five (45) days prior to operation above CLTP conditions.

(8) (PLA-6324-1) PPL will ensure that actions required to assure consistency between the CPPU containment analysis and SSES procedures will be implemented prior to operation above the current licensed power level.

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 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 identified the following areas for consideration by the NRC inspection staff during the licensee’s implementation of the proposed EPU:

- AREVA Neutronic Methods (License Condition 3.4.3)
- LTS and ATWS
- Power ascension testing activities (License Conditions 3.4.1 and 3.4.2)

These areas are recommended based on past experience with EPUs, the extent and unique nature of modifications necessary to implement the proposed EPU, and new conditions of operation necessary for the proposed EPU. They do not constitute inspection requirements but are intended to give inspectors insight into important bases for approving the EPU.

6.0 STATE CONSULTATION

In accordance with the Commission’s regulations, the NRC notified the Pennsylvania State official of the proposed issuance of the amendment. The State official had no comments.

7.0 ENVIRONMENTAL CONSIDERATION

Pursuant to 10 CFR 51.21, “Criteria for and Identification of Licensing and Regulatory Actions Requiring Environmental Assessments”; 10 CFR 51.32, “Finding of No Significant Impact”; 10 CFR 51.33, “Draft Finding of No Significant Impact; Distribution”; and 10 CFR 51.35, “Requirement to Publish Finding of No Significant Impact; Limitation on Commission Action,” the

NRC prepared a draft environmental assessment and finding of no significant impact, published in the *Federal Register* on August 21, 2007 (72 FR 46670). The draft environmental assessment provided a 30-day opportunity for public comment. The NRC staff received comments that were addressed in the final environmental assessment. The final environmental assessment was published in the *Federal Register* on December 17, 2007 (71 FR 71450). 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.

9.0 REFERENCES

1. B.T. McKinney (PPL), Letter to NRC, "Susquehanna Steam Electric Station Proposed License Amendment Numbers 285 for Unit 1 Operating License No. NPF-14 and 253 for Unit 2 Operating License No. NPF-22 Constant Pressure Power Uprate, PLA-6076," October 11, 2006; (Agencywide Documents and Access Management System (ADAMS) Accession No. ML062900160 (non-proprietary))

   Attachment 1, "Proposed Technical Specification Pages (Mark-up)," (ML062900160 (non-proprietary));

   Attachment 2, "Changes to Technical Specifications Bases Pages (Mark-up, Provided for Information)," (ML062900160 (non-proprietary));

   Attachment 3, "Supplemental Environmental Report," (ML062900161 (non-proprietary));

   Attachment 4, "Susquehanna Steam Electric Station Units 1 and 2 Safety Analysis Report for Constant Power Pressure Uprate," October 2006, (ML062900405 (proprietary));

   Attachment 5, "General Electric and Framatome ANP, Inc Affidavits," (ML062900161 (non-proprietary));

   Attachment 6, "Susquehanna Steam Electric Station Units 1 and 2 Safety Analysis Report for Constant Power Pressure Uprate," October 2006, (ML062900401 (non-proprietary));

   Attachment 7, "List of Planned Modifications," (ML062900401 (non-proprietary));

   Attachment 8, "Startup Testing," (ML062900306 (non-proprietary));

   Attachment 9, "Flow Induced Vibration Piping/Components Evaluation," (ML062900306 (non-proprietary));

   Attachment 10, "Steam Dryer Structural Evaluation," October 2006, (ML062900361 (proprietary));

Attachment 11, “Grid Stability and Evaluation,” (ML062900306 (non-proprietary));

Attachment 12, “RS-001 – Standard Review Plan Correlation Matrices,” (ML062900306 (non-proprietary));

Attachment 13, “RS-001 – Safety Evaluation Template,” (ML062900306 (non-proprietary));

Attachment 14, “Steam Dryer Structural Evaluation,” October 2006, (ML062900162 (non-proprietary));

Attachment 15, “General Electric and Continuum Dynamics Inc. Affidavits,” (ML062900162 (non-proprietary)).

2. B.T. McKinney (PPL), Letter to NRC, “Response to Request for Additional Information, Request for License Amendment—Extended Power Uprate,” PLA-6209, June 14, 2007. (ADAMS Accession Nos., ML071780629 (proprietary), ML071780627 (non-proprietary))

3. B.T. McKinney (PPL), Letter to NRC, “Response to Request for Additional Information, Request for License Amendment—Extended Power Uprate,” PLA-6175, April 17, 2007. (ADAMS Accession Nos. ML071150043 (proprietary), ML071150042 (proprietary))

4. B.T. McKinney (PPL), Letter to NRC, “Response to Request for Additional Information, Request for License Amendment—Extended Power Uprate,” PLA-6230, June 27, 2007. (ADAMS Accession Nos. ML071860424 (proprietary), ML071860421 (non-proprietary))

5. B.T. McKinney (PPL), Letter to NRC, “Response to Request for Additional Information, Request for License Amendment—Extended Power Uprate,” PLA-6250, July 30, 2007. (ADAMS Accession Nos.,ML072200103 (proprietary), ML072200101 (non-proprietary))

6. B.T. McKinney (PPL), Letter to NRC, “Reactor Systems Technical Review Request for Additional Information Responses,” PLA-6264, August 15, 2007. (ADAMS Accession Nos. ML072340604 (proprietary), ML072340603 (non-proprietary))

7. B.T. Parks (NRC), “Audit Plan for PPL Susquehanna, LLC Susquehanna Steam Electric Station Units 1 and 2 Extended Power Uprate Methods Review,” May 17, 2007, and Audit Report, “Core and Fuel Related Topics in Support of Constant Pressure Power Uprate for Susquehanna Steam Electric System Units 1 and 2,” June 12, 2007. (ADAMS Accession Nos. ML071370337 and ML071630155 (non-publicly available))

8. General Electric Company, “Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate” (known as ELTR1), NEDC-32424P-A, February 1999. (ADAMS Accession No. ML003680231 (proprietary))

9. General Electric Company, “Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate” (known as ELTR2), NEDC-32523P-A, February 2000; Supplement 1, Volume 1, February 1999; and Supplement 1, Volume II, April 1999. (ADAMS Accession Nos. ML003680243, ML003680449, and ML003703163 (proprietary))

10. General Electric Company, “Constant Pressure Power Uprate” (CLTR), NEDC-33004P-A, Revision 4, July 2003. (ADAMS Accession No. ML032170343 (proprietary))

11. PPL Susquehanna, "Susquehanna Steam Electric Station Updated Final Safety Analysis Report," Revision 62, December 2006.

12. Exxon Nuclear Company, "Generic Mechanical Design for Exxon Nuclear Jet Pump BWR Reload Fuel," XN-NF-85-67(P)(A), Revision 1, September 1986.

13. Advanced Nuclear Fuels Corporation, "Qualification of Exxon Nuclear Fuel for Extended Burnup," XN-NF-82-06(P)(A), Supplement 1, Revision 2, May 1988.

14. Siemens Power Corporation, "RODEX2A (BWR) Fuel Rod Thermal-Mechanical Evaluation Model," EMF-85-74(P)(A), Revision 0 and Supplements 1 and 2, February 1998.

15. Exxon Nuclear Company, "RODEX2 Fuel Rod Thermal-Mechanical Response Evaluation Model," XN-NF-81-58(P)(A), Revision 2 and Supplements 1 and 2, March 1984.

16. Exxon Nuclear Company, "Qualification of Exxon Nuclear Fuel for Extended Burnup," XN-NF-82-06(P)(A), Revision 1 and Supplements 2, 4, and 5, October 1986.

17. Advanced Nuclear Fuels Corporation, "Advanced Nuclear Fuels Corporation Critical Power Methodology for Boiling Water Reactors," ANF-524(P)(A) and Supplements 1 and 2, November 26, 1990.

18. Framatome ANP, "Susquehanna LOCA MAPLHGR Analysis for ATRIUM-10 Fuel and Extended Power Uprate," EMF-3243(P), Revision 0, November 2005 (ML070610373 (proprietary)).

19. W.H. Ruland (NRC), Letter to James F. Mallay, Framatome ANP, Inc., "'EMF-85-74(P)(A), Revision 0, Supplement 1 and Supplement 2, RODEX-2A (BWR) Fuel Rod Thermal-Mechanical Evaluation Model'—Clarification of Exposure Limit Applicable to Framatome ANP BWR Fuel (TAC No. MB6335)," December 17, 2002. (ADAMS Accession No. ML022810189)

20. Siemens Power Corporation, "Siemens Power Corporation Methodology for Boiling Water Reactors: Evaluation and Validation of CASMO-4/MICROBURN-B2," EMF-2158(P)(A), Revision 0, October 1999.

21. Exxon Nuclear Company, "Exxon Nuclear Methodology for Boiling Water Reactors, THERMEX: Thermal Limits Methodology Summary Description," XN-NF-80-19(P)(A), January 1987.

22. J.F. Klapproth (General Electric Company), letter to NRC, "Responses to Draft Request for Additional Information (RAI) to Licensing Topical Report NEDC-33004P, Revision 1 (TAC No. MB2510)," MFN 01-072, December 18, 2001. (ADAMS Accession No. ML021350600)

23. R.V. Guzman (NRC), Letter to Britt T. McKinney (PPL), "Susquehanna Steam Electric Station, Units 1 and 2—Issuance of Amendment Re: Standby Liquid Control System," February 28, 2007. (ADAMS Accession No. ML070390215)

24. U.S. Nuclear Regulatory Commission, "Inadequate Standby Liquid Control System Relief Valve Margin," Information Notice 2001-13, August 10, 2001.

25. B.T. McKinney (PPL), Letter to NRC, "Proposed License Amendment Numbers 279 for Unit 1 Operating License No. NPF-14 and 248 for Unit 2 Operating License No. NPF-22 ARTS/MELLLA Implementation," PLA-5931, November 18, 2005.

26. General Electric Company, "Generic Electric Standard Application for Reactor Fuels, 'NEDE-24011-P-A and NEDE-24011-P-A-US,'" (GESTAR-II, latest approved version).

27. Framatome ANP, "EXEM BWR-2000 ECCS Evaluation Model," EMF-2361(P)(A), Revision 0, May 2001.

28. Advanced Nuclear Fuels Corporation, "Advanced Nuclear Fuels Corporation Methodology for Boiling Water Reactors EXEM BWR Evaluation Model," ANF-91-048(P)(A), January 1993.

29. Exxon Nuclear Company, "HUXY: A Generalized Multirod Heatup Code with 10 CFR 50 Appendix K Heatup Option Users Manual," XN-CC-33(P)(A), Revision 1, November 1975.

30. Exxon Nuclear Company, "RODEX2 Fuel Rod Thermal Mechanical Response Evaluation Model," XN-NF-81-58(P)(A), Revision 2 and Supplements 1 and 2, March 1984.

31. Framatome ANP, "Susquehanna LOCA Break Spectrum Analysis for ATRIUM-10 Fuel and Extended Power Uprate," EMF-3242(P), Revision 0, November 2005. (ML070610375 (proprietary).

32. Nuclear Management and Resources Council, "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors," NUMARC-87-00, November 1987.

33. B.T. McKinney (PPL), Letter to NRC, "Instrumentation and Controls Technical Review Request for Additional Information—Extended Power Uprate," PLA-6204, June 1, 2007. (ADAMS Accession No. ML071620342 (proprietary))

34. B.T. McKinney (PPL), Letter to NRC, "Susquehanna Steam Electric Station Proposed License Amendment Number 285 for Unit 1 Operating License No. NPF-14 and Unit 2 Operating License No. NPF-22 Extended Power Uprate Application, Supplement to Instrumentation and Controls and Balance-of-Plant Safety Systems Request for Additional Information Responses," PLA-6236, July 13, 2007. (ADAMS Accession No. ML072060604)

35. B.T. McKinney (PPL), Letter to NRC, "Instrumentation and Controls Technical Review Request for Additional Information—Extended Power Uprate," PLA-6254, August 3, 2007. (ADAMS Accession No. ML072280247)

36. B.T. McKinney (PPL), Letter to NRC, "Proposed License Amendment Numbers 285 for Unit 1 Operating License No. NPF-14 and 253 for Unit 2 License NPF-22—Extended Power Uprate Application Regarding Steam Dryer and Flow Effects Request for Additional Information Responses," PLA-6176, April 27, 2007. (ADAMS Accession Nos. ML071300266 (proprietary), ML071300265 (non-proprietary))

37. B.T. McKinney (PPL), Letter to NRC, “Supplement to Proposed License Amendment Numbers 285 for Unit 1 Operating License No. NPF-14 and 253 for Unit 2 License NPF-22 Extended Power Update Application Re: Mechanical and Civil Engineering Technical Review Request for Additional Information Responses,” PLA-6200, June 1, 2007. (ADAMS Accession Nos. ML071620299 (proprietary), ML071620288 (non-proprietary))

38. B.T. McKinney (PPL), Letter to NRC, “Proposed License Amendment Numbers 285 for Unit 1 Operating License No. NPF-14 and 253 for Unit 2 License NPF-22—Extended Power Uprate Application Regarding Steam Dryer and Flow Effects Request for Additional Information Responses,” PLA-6242, July 31, 2007. (ADAMS Accession Nos. ML072220480, ML072220482, ML072220477, ML072220485, ML072220490 (proprietary))

39. B.T. McKinney (PPL), Letter to NRC, “Supplement to Proposed License Amendment Numbers 285 for Unit 1 Operating License No. NPF-14 and 253 for Unit 2 License NPF-22—Constant Pressure Power Uprate Application Regarding Steam Dryer and Flow Effects Verbal and Confirmatory Request for Additional Information Responses,” PLA-6255, August 13, 2007. (ADAMS Accession Nos. ML072340577 (proprietary), ML072340597 (nonproprietary))

40. B.T. McKinney (PPL), Letter to NRC, “Susquehanna Steam Electric Station Proposed License Amendment Number 285 for Unit 1 Operating License No. NPF-14 and Unit 2 Operating License No. NPF-22 Extended Power Uprate Application, Balance-of-Plant Safety System Request for Additional Information Response PLA-6198,” PLA-6198, May 14, 2007. (ADAMS Accession No. ML071500058)

41. R.V. Guzman (NRC), Letter to B.T. McKinney (PPL), “Request for Additional Information (RAI) - Susquehanna Steam Electric Station, Units 1 and 2 (SSES 1 and 2)—Extended Power Uprate Application Re: Balance-of-Plant Safety Systems Review,” April 16, 2007. (ADAMS Accession No. ML071020315)

42. B.T. McKinney (PPL), Letter to NRC, “Susquehanna Steam Electric Station Proposed License Amendment Number 285 for Unit 1 Operating License No. NPF-14 and Unit 2 Operating License No. NPF-22 Extended Power Uprate Application, Regarding Change to Technical Specification SR 3.7.1—Residual Heat Removal Service Water System (RHRSW) and the Ultimate Heat Sink (UHS), PLA-6266,” PLA-6266, August 28, 2007.

43. B.T. McKinney (PPL), Letter to NRC, “Susquehanna Steam Electric Station Proposed License Amendment Number 285 for Unit 1 Operating License No. NPF-14 and Proposed License Amendment No. 253 for Unit 2 Operating License No. NPF-22 Extended Power Uprate Application—Supplement, PLA-6290,” October 5, 2007. (ML072900420)

44. STUDSVIK/SOA-95/2, “CASMO-4, A Fuel Assembly Burnup Program Methodology,” Studsvik Proprietary, September 1995. (ADAMS Accession No. ML072980097 (proprietary))

45. Siemens Power Corporation, “MICROBURN-B2: Steady State BWR Core Physics Method,” EMF-1833(P), Revision 2, September 1998. (ADAMS Accession No. ML072980096 (proprietary))

46. GE Nuclear Energy, “General Electric Model for LOCA Analysis in accordance with 10 CFR 50 Appendix K,” NEDE-20566-P-A, September 1986.

47. General Electric Nuclear Energy, “BWR Owner’s Group Long-Term Stability Solutions Licensing Methodology,” NEDO-31960, May 1991.

48. General Electric Nuclear Energy, “Reactor Stability Detector and Suppress Solutions Licensing Basis Methodology for Reload Applications,” NEDO-32465-A, August 1996.

49. H. Spierling, "Initial Void Measurements at the Karlstein Thermal Hydraulic Test Loop," A1C-1308656-1, April 30, 2003.

50. U.S. Nuclear Regulatory Commission, “Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions,” GL 96-06, September 30, 1996.

51. Framatome ANP, “Enhanced Option III Long Term Stability Solution,” ANP-10262(P), Revision 0, January 2006. (ADAMS Accession No. ML060330652 (proprietary))

52. AREVA, “Response to Request for Additional Information—ANP-10262(P),” ANP-10262Q1P, Revision 0, August 2007. (ADAMS Accession No. ML072280229 (proprietary))

53. AREVA, “Applicability of AREVA NP BWR Methods to Extended Power Uprate Conditions,” ANP-2638(P), Revision 0, July 2007. (ADAMS Accession No. ML072180378 (proprietary))

54. H. Spierling, S. Misu, and H. Moon, “Fuel Rod Gamma Scan of a Siemens ATRIUM-10 Fuel Assembly,” *Trans. Am. Nucl. Soc.*, Boston, Massachusetts, June 1999.

55. B.T. McKinney (PPL), Letter to NRC, “Supplement to Proposed License Amendment Numbers 285 for Unit 1 Operating License No. NPF-14 and 253 for Unit 2 License NPF-22 Constant Pressure Power Uprate,” PLA -6306, November 30, 2007 (ML073450822 (non-proprietary), ML073450826 (proprietary))

56. R.V. Guzman (NRC), Letter to B.T. McKinney (PPL), “Request for Additional Information (RAI) - Susquehanna Steam Electric Station, Units 1 and 2 (SSES 1 and 2)—Extended Power Uprate Application Re: Operator Licensing and Human Performance Technical Review,” April 12, 2007 (ML071000126).

57. B.T. McKinney (PPL), Letter to NRC, “Susquehanna Steam Electric Station Proposed License Amendment Number 285 for Unit 1 Operating License No. NPF-14 and Unit 2 Operating License No. NPF-22 Extended Power Uprate Application Re: Operator Licensing and Human Performance Technical Review Request for Additional Information Responses,” PLA-6189, May 3, 2007 (ML071360026).

57. ANP-10262Q1P, Revision 1, Response to Request for Additional Information - ANP-10262(P). AREVA. October 2007.

58. General Electric Company, "Qualification of the One Dimensional Core Transient Model (ODYN) for Boiling Water Reactors," NEDC-24154P-A, Supplement 1, Volume 4, February, 2001.

59. General Electric Company, “The General Electric Mark III Pressure Suppression Containment System Analytical Model,” NEDO-20533, June 1974.

60. Moody, F.J., “Maximum Flow Rate of a Single Component, Two Phase Mixture,” Transaction of the ASME, Volume 87, Series C, 1966.

61 B.T. McKinney (PPL), Letter to NRC, “Containment and Ventilation Technical Review Request for Additional Information Responses,” PLA-6203, June 4, 2007 (ML071700096).

62. General Electric Company, MC3PT, “The General Electric Mark III Pressure Suppression Containment Analytical Model,” NEDO-20533, June 1974, and Supplement 1, September 1975; and SHEX, “The General Electric Pressure Suppression Containment Analytical Model,” NEDO-10320, April 1971 (Supplement 1, May 1971; Supplement 2, January 1973).

63. Shrock, V.E., “A Revised ANS Standard for Decay Heat from Fission Products,” Nuclear Technology, Volume 46, Page 323, 1979; and American Nuclear Society, ANSI/ANS 5.1-1979, “Decay Heat Power in Light Water Reactors,” Hinsdale, Illinois, 1979.

64. GE Nuclear Energy, Service Information Letter No. 636, “Additional Terms Included in Reactor Decay Heat Calculations,” May 24, 2001.

65. U.S. Nuclear Regulatory Commission, “Service Water System Problems Affecting Safety-Related Equipment,” GL 89-13, July 18, 1989.

66. Anderson, C., “Mark II Containment Program Load Evaluation and Acceptance Criteria,” NRC, NUREG-0808, August 1981.

67. U.S. Nuclear Regulatory Commission, “Mark II Containment Lead Plant Program Load Evaluation and Acceptance Criteria,” NUREG-0487, October 1978.

    U.S. Nuclear Regulatory Commission, “Mark II Containment Lead Plant Program Load Evaluation and Acceptance Criteria,” NUREG-0487, Supplement 1, September 1980.

68. Su, T.M., “Suppression Pool Temperature Limits for BWR Containments,” NUREG-0783, November 1981.

69. General Electric, NEDO-32686, Revision 0, “Utility Resolution Guidance for ECCS Suction Strainer Blockage.”

70. B.T. McKinney (PPL), Letter to NRC, “Susquehanna Steam Electric Station Proposed License Amendment Number 285 for Unit 1 Operating License No. NPF-14 and Proposed License Amendment No. 253 for Unit 2 Operating License No. NPF-22 Constant Pressure Power Uprate - Supplement, PLA-6237,” July 6, 2007. (ML072010337)

Attachment:
List of Acronyms

Principal Contributors:

G. Singh	V. Goel	A. Black
J. Tsao	G. Makar	T. Scarbrough
C. Wu	A. DuBouchet	J. Tatum
A. Stubbs	D. Harrison	R. Lobel
B. Lee	J. Parillo	W. Jensen
D. Jackson	B. Parks	P. Lien
R. Pettis	J. Quichocho	G. Armstrong
A. Lewin	R. Guzman	P. Yarsky

Date: January 30, 2008

ATTACHMENT - LIST OF ACRONYMS

ACRONYM	DEFINITION
AAF	acceptable as found
AAL	acceptable as left
ac	alternating current
ACM	acoustic circuit model
ADAMS	Agencywide Documents Access and Management System
ADS	automatic depressurization system
AL	analytical limit
ALARA	as low as reasonably achievable
ANS	American Nuclear Society
ANSI	American National Standards Institute
AOO	anticipated operational occurrence
AOP	abnormal operating procedure
AOV	air-operated valve
AP/JR	annulus pressurization/jet reaction
APLHGR	average planar linear heat generation rate
APRM	average power range monitor
ARAVS	auxiliary and radwaste area ventilation system
ARI	alternate rod injection
ARTS	average power range monitor, rod block monitor technical specifications
ASEP	Accident Sequence Evaluation Program
ASME	American Society of Mechanical Engineers
AST	alternative source term
ASTM	American Society for Testing and Materials
ATWS	anticipated transient without scram
AV	allowable value
BOP	balance of plant
BTP	branch technical position

ACRONYM	DEFINITION
BWR	boiling-water reactor
BWROG	Boiling Water Reactor Owners Group
BWRVIP	Boiling Water Reactor Vessels and Internals Project
cal/gm	calories per gram
CDF	core damage frequency
ΔCDF	change in core damage frequency
CDI	Continuum Dynamics, Inc.
CFR	*Code of Federal Regulations*
CFS	condensate and feedwater system
CLTP	current licensed thermal power (3489 MWt)
CLTR	constant pressure power uprate licensing topical report
CO	condensation oscillation
COLR	core operating limit report
CPPU	constant pressure power uprate
CPR	critical power ratio
CRAVS	control room area ventilation system
ΔCPR	Change in critical power ratio
CRD	control rod drive
CRDA	control rod drop accident
CRD-HSR	control rod drive-hydraulic system return
CRDS	control rod drive system
CRHE	control room habitability envelope
CREOASS	control room emergency outside air supply system
CS	core spray
CSC	containment spray cooling
CSS	core support structure
CST	condensate storage tank
CUF	cumulative usage factor

ACRONYM	DEFINITION
CWS	circulating water system
DBA	design-basis accident
dc	direct current
DHR	decay heat removal
DIVOM	delta critical power ratio (CPR) over initial CPR versus oscillation magnitude
DSS	detect and suppress
ECCS	emergency core cooling system
ECP	electrochemical potential
EDG	emergency diesel generator
EFDS	equipment and floor drainage system
EFPY	effective full-power year
ELTR1	GE Licensing Topical Report NEDC-32424P-A
ELTR2	GE Licensing Topical Report NEDC-32523P-A
EMA	equivalent margins analysis
EOC	end of cycle
EOP	emergency operating procedure
EOS	emergency overspeed
EPRI	Electric Power Research Institute
EPU	extended power uprate
EQ	environmental qualification
ESF	engineered safety feature
ESFAS	engineered safety feature actuation system
ESFVS	engineered safety feature ventilation system
ESSW	essential safeguards service water
ESW	emergency service water
ESWS	emergency service water system
EU	Electric Utilities
EVT	enhanced visual testing
F&O	fact and observation

ACRONYM	DEFINITION
FAC	flow-accelerated corrosion
FEM	finite-element model
FIV	flow-induced vibration
FPC	fuel pool cooling
FR	*Federal Register*
ft^2	square foot/feet
ft-lb	foot-pound(s)
FPCS	fuel pool cooling system
fps	foot/feet per second
FSAR	final safety analysis report
FW	feedwater
GDC	general design criterion/criteria
GE	General Electric
GENE	General Electric Nuclear Energy
GESTAR	General Electric Standard Application for Reactor Fuels
GL	generic letter
gpm	gallon(s) per minute
GUN-B	Gundremmingen Unit B
GWd/ST	gigawatt day(s) per short ton
GWMS	gaseous waste management systems
h	hour
HCLPF	high confidence of low probability of failure
HELB	high-energy line break
HEP	human error probability
HEPA	high-efficiency particulate air
HP	high pressure
HPCI	high-pressure coolant injection
HRA	human reliability analysis
HWC	hydrogen water chemistry

ACRONYM	DEFINITION
HVAC	heating, ventilating, and air conditioning
hz	Hertz
IASCC	irradiation-assisted stress-corrosion cracking
IGSCC	intergranular stress-corrosion cracking
ICAs	Interim Corrective Actions
IHSI	inductive heating stress improvement
IN	information notice
IPE	individual plant examination
IPEEE	individual plant examination of external event
IRM/SRM/LP RM	Intermediate range/source range/local power range monitor
ISP	integrated surveillance program
IST	inservice testing
kV	kilovolt(s)
kW/ft	kilowatt(s) per foot
LAR	license amendment request
lbm/s	pound mass per second
LCO	limiting condition for operation
LEFM	leading edge flow meter
LER	licensee event report
LERF	large early release frequency
LES	large eddy simulation
LFWH	loss of feedwater heater
LHGR	linear heat generation rate
LOCA	loss-of-coolant accident
LOFW	loss of feedwater
LOOP	loss of offsite power
LP	low pressure
LPCI	low-pressure coolant injection

ACRONYM	DEFINITION
LPCS	low-pressure core spray
LPRM	local power range monitor
LRNBP	load rejection with no turbine bypass
LTR	licensing topical report
LTS	long-term stability solution
LWMS	liquid waste management system
M-G	motor-generator
M&TE	measurement and test equipment
MAAC	Mid-Atlantic Area Council
MAAP	material access authorization program
MAPLHGR	maximum average planar linear heat generation rate
MCPR	minimum critical power ratio
MCS	main condenser system
MELLLA	maximum extended load line limit analysis
MeV	megaelectronvolt
µmho/cm	micro-mho per centimeter
Mlb/h	million pounds per hour
Mlbm/h	Million pounds mass per hour
MOV	motor-operated valve
MOX	mixed oxide
MS	main steam
MSIP	mechanical stress improvement process
MSIV	main steam isolation valve
MSIVF	main steam isolation valve closure with flux scram
MSL	main steamline
MSLB	main steamline break
MSRV	main steam relief valve
MSSS	main steam supply system
MVA	megavolt ampere(s)

ACRONYM	DEFINITION
MVAR	megavolt amperes reactive
MWD/MT	megawatt day(s)/metric ton
MWe	megawatt(s) electric
MWR	metal-water reaction
MWt	megawatt(s) thermal
n/cm^2	neutron(s) per centimeter squared
NEI	Nuclear Energy Institute
NEPA	National Environmental Policy Act
NPSH	net positive suction head
NRC	U.S. Nuclear Regulatory Commission
NSSS	nuclear steam supply system
NUMARC	Nuclear Management and Resource Council, Inc.
OBE	operating-basis earthquake
OLMCPR	operating limit minimum critical power ratio
OLTP	original licensed thermal power (3293 MWt)
OPRM	oscillation power range monitor
P-T	pressure-temperature
PATP	power ascension and test progam
PCT	peak cladding temperature
PD	penetrant testing
PGA	peak ground acceleration
PJM	Pennsylvania, New Jersey, Maryland Interconnection, LLC (Mid-Atlantic region power pool)
ppb	part(s) per billion
PPL	PPL Susquehanna, LLC (the licensee)
PRA	probabilistic risk assessment
psi	pound(s) per square inch
psid	pound(s) per square inch differential
psig	pound(s) per square inch gauge

ACRONYM	DEFINITION
Pu	plutonium
pu	per unit
PUSAR	power uprate safety analysis report
QC2	Quad Cities Unit 2
QST	quality steam turbine
RACWS	reactor auxiliary cooling water systems
RAI	request for additional information
RCIC	reactor core isolation cooling
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
rem	roentgen equivalent man
RFP	reactor feedwater pump
RFPT	reactor feedwater pump turbine
RG	regulatory guide
RHR	residual heat removal
RHRSW	residual heat removal service water
RHRSWS	residual heat removal service water system
RIPD	reactor internal pressure difference
RIS	regulatory issue summary
RPS	reactor protection system
RPT	recirculation pump trip
RPV	reactor pressure vessel
RR	reactor recirculation
RRS	reactor recirculation system
RS	review standard
RSLB	recirculation suction line break
RTP	rated thermal power
RV	reactor vessel
RWM	rod worth minimizer

ACRONYM	DEFINITION
SAFDLs	specified acceptable fuel design limits
SBO	station blackout
SCC	stress-corrosion cracking
SDC	shutdown cooling
SE	safety evaluation
SER	safety evaluation report
SFP	spent fuel pool
SFPAVS	spent fuel pool area ventilation system
SGTS	standby gas treatment system
SIL	service information letter
SL	safety limit
SLC	standby liquid control
SLCS	standby liquid control system
SLMCPR	safety limit minimum critical power ratio
SMA	seismic margins assessment
SME	seismic margin earthquake
SMT	scale model testing
SNM	susceptible nonmodeled
SORV	stuck-open relief valve
SPC	suppression pool cooling
SPDS	safety parameter display system
SR	surveillance requirement
SRP	Standard Review Plan
SRSS	square root of the sum of the squares
SRV	safety relief valve
SSC	structure, system, and component
SSE	safe-shutdown earthquake
SSEL	safe-shutdown equipment list
SSES	Susquehanna Steam Electric Station

ACRONYM	DEFINITION
STS	Standard Technical Specification
SUPF	stress underprediction factor
Sv	sievert
SWS	service water system
T-G	turbine-generator
TAVS	turbine area ventilation system
TEDE	total effective dose equivalent
TGSS	turbine gland sealing system
TIP	traversing in-core probe
TRC	time reliability correlation
TS	technical specification
TSBS	turbine steam bypass system
TTNBP	turbine trip with no bypass
UFSAR	updated final safety analysis report
UHS	ultimate heat sink
USE	upper-shelf energy