SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 174 TO FACILITY OPERATING LICENSE NO NPF-57

PSEG NUCLEAR LLC

HOPE CREEK GENERATING STATION

DOCKET NO. 50-354

Proprietary information pursuant to
Title 10 of the *Code of Federal Regulations* Section 2.390
has been redacted from this document.
Redacted information is identified by blank space enclosed within double brackets

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APPENDIX A – Steam Dryer

1.0 INTRODUCTION

1.1 Application

By letter dated September 18, 2006,[1] as supplemented by additional letters,[2] PSEG Nuclear, LLC (PSEG or the licensee) submitted an amendment request for an extended power uprate (EPU) for the Hope Creek Generating Station (Hope Creek). The proposed amendment would increase the authorized maximum power level by approximately 15 percent, from the current licensed thermal power (CLTP) of 3,339 megawatts thermal (MWt) to 3,840 MWt.

The supplemental letters received between May 3, 2007, and May 2, 2008, contained clarifying information that did not change the initial no significant hazards consideration determination noticed in the *Federal Register* on May 3, 2007 (72 FR 24627), and did not expand the scope of the original application.

1.2 Background

Hope Creek is a boiling-water reactor (BWR) plant of the BWR/4 design with a Mark-I containment. The Nuclear Regulatory Commission (NRC or Commission) licensed Hope Creek on July 25, 1986, under NPF-57[3] for full-power operation at the original rated thermal power (OLTP) of 3,293 MWt, and Hope Creek entered commercial operation on December 20, 1986. In License Amendment 131,[4] dated July 30, 2001, the Hope Creek licensed thermal power limit was increased by approximately 1.4 percent from 3,293 MWt to 3,339 MWt (i.e., the current power level). The 1.4 percent power change was based on the installation of the CE Nuclear Power LLC Crossflow ultrasonic flow measurement system and its ability to achieve increased accuracy in measuring feedwater flow.

The Hope Creek site is located on the southern part of Artificial Island on the east bank of the Delaware River in Lower Alloways Creek Township, Salem County, New Jersey. While called Artificial Island, the site is actually connected to the mainland of New Jersey by a strip of tideland formed by hydraulic fill from dredging operations on the Delaware River by the U.S. Army Corps of Engineers. The site is 15 miles south of the Delaware Memorial Bridge, 18 miles south of Wilmington, Delaware, 30 miles southwest of Philadelphia, Pennsylvania, and 7-1/2 miles southwest of Salem, New Jersey. The nearest population center to the Artificial Island site is Newark, Delaware, with a population of 28,547 people, according to data collected by the Bureau of Census in the Census 2000 Summary.

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[1] Agencywide Documents Access and Management System (ADAMS) Accession Number ML062680451

[2] October 10, 2006 (ML062920092); October 20, 2006 (ML063110164); February 14, 2007 (ML070530099); February 16, 2007 (ML070590182); February 28, 2007 (ML070680314); March 13, 2007 (ML070790508 & ML070810360); March 22, 2007 (ML070930442); March 30, 2007 (ML071010243 & ML070960103); April 13, 2007 (ML071140157); April 18, 2007 (ML071160121); April 30, 2007 (ML071290559); May 10 (ML071360375); May 18, 2007 (ML071500294, ML071720368, & ML071500317); May 24, 2007 (ML071630305); June 22, 2007 (ML071840167); July 12, 2007 (ML072110215); August 3, 2007 (ML072250369); August 17, 2007 (ML072480515); August 27, 2007 (ML072480570); August 31, 2007 (ML072540651); September 11, 2007 (ML072640410); October 10, 2007 (ML080580475); October 23, 2007 (ML073040393); November 15, 2007 (ML073320601); November 30, 2007 (ML073460793); December 31, 2007 (ML080080577); January 14, 2008 (ML080230069); January 15, 2008 (ML080250028); January 16, 2008 (ML080290663); January 18, 2008 (ML080280531); January 25, 2008 (ML080360467); January 30, 2008 (ML080420468); March 18, 2008 (ML080860477 & ML080870082); and May 2, 2008 (ML081270387).

[3] ADAMS Accession No. ML011760205

[4] ADAMS Accession No. ML011910345

The construction permit for Hope Creek was issued by the Atomic Energy Commission (AEC) on November 4, 1974.[5] The plant was designed and constructed based on Appendix A to Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, "General Design Criteria for Nuclear Power Plants," in the *Federal Register* (36 FR 3255) on February 20, 1971 (hereinafter referred to as "final GDC"). The 64 GDCs establish minimum requirements for the principal design criteria for water-cooled nuclear power plants including Hope Creek.

As discussed in the Hope Creek Updated Final Safety Analysis Report (UFSAR),[6] Section 3.1, "Conformance With the NRC General Design Criteria," for each of the 64 criteria in the GDC, a specific assessment of the plant design has been made. In addition, a list of Hope Creek UFSAR sections where further information pertinent to each criterion is also provided.

1.3 Licensee's Approach

The licensee for Hope Creek applied for an EPU by letter dated September 18, 2006.[7] The licensee's application for the proposed Hope Creek EPU was prepared following the guidelines contained in General Electric (GE) Licensing Topical Report (LTR) NEDC-33004P-A, "Constant Pressure Power Uprate," Revision 4, dated July 31, 2003.[8] The constant pressure power uprate (CPPU) LTR, hereafter referred to as the CLTR, was approved by the NRC in a final safety evaluation (SE) dated March 31, 2003.[9] The CLTR provided appropriate guidelines for CPPU applications with a core exclusively using GE fuel. Some topics in the CLTR are directly fuel dependent, because the fuel type affects the resulting evaluation or the consequences of transients or accidents. Because the first cycle Hope Creek EPU core (Cycle 15) will contain some non-GE (Westinghouse SVEA-96+) fuel, the CLTR was not referenced as the basis for areas involving reactor systems and fuel issues, consistent with the "Conditions and Limitations" identified in the staff SE for using the CLTR.

For the fuel-dependent topics, the evaluation methods from General Electric LTR NEDC-32424P-A (February 1999), "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," (ELTR1)[10] and in Section 4.8 of Supplement 1 of GE LTR, NEDC-32523P-A (February 2000), "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate" (ELTR2)[11] are applied. In general, the licensee's plant-specific engineering evaluations supporting the power uprate were performed in accordance with guidance contained in ELTR1. This topical report was previously reviewed and endorsed by the NRC staff. For some items, bounding analyses and evaluations provided in GE LTR, ELTR2 were cited. The NRC staff has also previously approved ELTR2.

The approach to achieving a CPPU for Hope Creek consists of: (1) an increase in the core thermal power with a more uniform power distribution achieved by better fuel management techniques to create increased steam flow; (2) a corresponding increase in the FW system flow; (3) no increase in maximum core flow; and (4) reactor operation primarily along the maximum extended load line limit analysis (MELLLA) rod/flow lines. This approach is based on the NRC-approved BWR EPU guidelines contained in the CLTR, ELTR1, and ELT2 topical reports.

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[5] ADAMS Accession No. ML011760627
[6] Hope Creek Generating Station Updated Final Safety Analysis Report, Revision 14, dated July 26, 2005. ADAMS Accession No. ML052220616
[7] ADAMS Accession No. ML062680451
[8] ADAMS Accession No. ML032170332
[9] ADAMS Accession No. ML031190318
[10] ADAMS Accession No. ML003680231
[11] ADAMS Accession No. ML003712826

Additional LTRs used in the licensee's evaluation include NEDC-32424P-A, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," February 1999[12] and NEDC-32523P-A, "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate," February 2000.[13]

Attachment 4 to the Licensee's original application contains GE Report NEDC-33076P, Revision 2,[14] which is the Power Uprate Safety Analysis Report (PUSAR) for Hope Creek. This report summarizes the results of safety analyses and evaluations performed by GE, justifying the proposed Hope Creek EPU. The PUSAR follows the generic content and format using the CPPU approach to uprating reactor power, as described in the CLTR. A non-proprietary (i.e., publicly available) version of the PUSAR is contained in Attachment 12 to the licensee's application.[15]

The proposed method for achieving the higher steam flow necessary for the proposed 15 percent EPU for Hope Creek, would be accomplished by retaining the existing MELLLA power/flow map and increasing core flow (and power) along the MELLLA upper boundary line as shown in Figure 1-1 in the PUSAR. (Attachment 4, page 1-20 of the licensee's application).[13] The current MELLLA power/flow map was approved in Hope Creek Amendment No. 163, dated February 8, 2006.[16] As discussed in Section 2.1 of the PUSAR, the additional energy requirements for CPPU are met by an increase in the bundle enrichment, an increase in the reload fuel batch size, and/or changes in fuel loading pattern to maintain the desired plant operating cycle length.

PSEG, the licensee for Hope Creek, referenced GE LTR NEDC-33173P, "Applicability of GE Methods to Expanded Operating Domains," February 10, 2006,[17] in its application. This report is based on the NRC staff-approved approach taken by the Vermont Yankee Nuclear Generating Station for applying the GE analytical methods for CPPU operating domains.

The NRC staff SER for NEDC-33173P, "Applicability of GE Methods to Expanded Operating Domains," dated January 17, 2008,[18] specifies the limitations that apply to NEDC-33173P.

PSEG referenced NEDC-33173P to justify application of GE methods to HCGS EPU. Each limitation specified in the NRC staff SE for NEDC-33173P was evaluated for acceptability for HCGS EPU. In addition, the NRC staff evaluation of applicability of NEDC-33173P, specifically to GE14 for HCGS Cycle 15, is discussed in Section 2.8.7.

Table 1-3 of the PUSAR provides a summary of the reactor thermal-hydraulic parameters for CLTP plant operating conditions and CPPU/Hope Creek EPU operating conditions (Attachment 4, page 1-19 of the licensee's application).

The licensee plans to implement the Hope Creek EPU in two steps: (1) an 11.5-percent increase from 3,339 MWt to 3,723 MWt will occur during Cycle 15; then (2) a 3.5-percent increase from 3,723 MWt to 3,840 MWt will occur during a subsequent operating cycle. The

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[12] ADAMS Accession No. ML003680231
[13] ADAMS Accession No. ML003712826
[14] ADAMS Accession No. ML062690073
[15] ADAMS Accession No. ML062680451
[16] ADAMS Accession No. ML060370377
[17] ADAMS Accession No. ML060450677
[18] ADAMS Accession No. ML073340231

licensee needs to complete steam turbine changes to the first four-stages of stationary blading (diaphragms) to implement the 3.5-percent increase during an outage no sooner than the spring of 2009. Subsequently, the plant will be operated at 3,840 MWt starting no sooner than Cycle 16 (i.e., during the operating cycle following the outage that completes the changes to the first four-stages of stationary blading for the steam turbine).

1.4 Plant Modifications

The licensee determined that plant modifications were necessary to implement the proposed Hope Creek EPU. The following is a list of these modifications:

Completed Modifications

- Additional 500 kilovolt circuit breaker in Hope Creek switchyard
- Cooling tower fill and flow distribution modifications
- Low pressure turbine replacement
- Electrohydraulic control and turbine supervisory instrumentation replacement main transformer replacement
- Main generator stator water cooling upgrade
- Turbine moisture separator upgrade
- Piping vibration monitoring
- Average power range monitor and rod block monitor flow-biased trip reference card replacement
- Isolated phase bus duct cooling modification
- Steam jet air ejector modification
- Feedwater heater dump valve replacements
- Moisture separator and 5th point feedwater heater re-rating
- High pressure turbine replacement
- Reactor core isolation cooling (RCIC) turbine exhaust pressure trip setpoint and snubber installation
- Pipe support modifications (where required)
- Small bore piping modifications for flow induced vibration (where required)

The NRC staff's evaluation of the licensee's plant modifications, within the scope of the areas of review, is provided in Section 2.0 of this SE.

1.5 Method of NRC Staff Review

The NRC staff's review of the Hope Creek EPU application is based on NRC Review Standard RS-001, "Review Standard for Extended Power Uprates," Revision 0 (December 2003).[19] RS-001 contains guidance for evaluating each area of review in the application, including the specific GDC used as the NRC's acceptance criteria. The guidance in RS-001 is based on the final GDC. In addition to RS-001, the NRC staff used applicable rules, regulatory guides, Standard Review Plan (SRP) sections, and NRC staff positions on the topics being evaluated.

The staff requested that the licensee identify all codes and methodologies used to obtain safety limits (SLs) and operating limits and explain how they verified these limits were correct for the

[19] ADAMS Accession No. ML033640024

uprate reactor core. The licensee was also requested to identify and discuss any limitations imposed by the staff on the use of these codes and methodologies.

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 Hope Creek EPU on design-basis analyses. The NRC staff evaluated the licensee's application and supplements. The NRC staff also performed audits, performed independent calculations, analyses, and evaluations as noted below.

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

Audits supporting the proposed Hope Creek EPU were conducted by the NRC staff and its contractors in relation to the following topics:

- steam dryer structural integrity analyses (see SE Section 2.2.6)
- reactor neutronic and thermal/hydraulic analyses (see SE Section 2.8.7)

Independent confirmatory calculations, analyses, and evaluations were performed by the NRC staff and its contractors in relation to the following topics:

- reactor vessel pressure-temperature limits (see SE Section 2.1.2)
- emergency core cooling system (ECCS) performance (see SE Section 2.8.5.6.2)

2.0 EVALUATION

2.1 Materials and Chemical Engineering

2.1.1 Reactor Vessel Material Surveillance Program

Regulatory Evaluation

The reactor vessel material surveillance program provides a means for determining and monitoring the fracture toughness of the reactor vessel beltline materials to support analyses for ensuring the structural integrity of the ferritic components of the reactor vessel. The NRC staff's review focused primarily on the effects of the proposed Hope Creek EPU on the licensee's reactor vessel surveillance capsule withdrawal schedule. The NRC's acceptance criteria are based on: (1) GDC-14, insofar as it 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, insofar as it requires that the RCPB be designed with margin sufficient to assure that, under specified conditions, it will behave in a non-brittle manner and the probability of a rapidly propagating fracture is minimized; (3) 10 CFR Part 50, Appendix H, which provides for monitoring changes in the fracture toughness properties of materials in the reactor vessel beltline region; and (4) 10 CFR 50.60, which requires compliance with the requirements of 10 CFR Part 50, Appendix H. Specific review criteria used for the Hope Creek Hope Creek EPU are contained in SRP Section 5.3.1 and other guidance provided in Matrix 1 of Power Uprate Review Standard RS-001.[20]

Technical Evaluation

The NRC's regulatory requirements related to the establishment and implementation of a facility's reactor vessel materials surveillance program and surveillance capsule withdrawal schedule are given in 10 CFR Part 50, Appendix H. Two specific alternatives are provided with regard to the design of a facility's reactor vessel surveillance program which may be used to address the requirements of Appendix H to 10 CFR Part 50.

The first alternative is the implementation of a plant-specific reactor vessel 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 reactor vessel surveillance program, a licensee may use the edition of ASTM Standard Practice E 185, which was current on the issue date of the American Society of Mechanical Engineers *Boiler and Pressure Vessel Code* (ASME Code) to which the reactor vessel 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). An ISP is defined in Appendix H to 10 CFR Part 50 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."

[20] NRC Review Standard RS-01, "Review Standard for Extended Power Uprates," Revision 0 (December 2003) ADAMS Accession No. ML033640024.

The licensee for Hope Creek discussed the impact of Hope Creek EPU on the reactor vessel material surveillance program in Section 3.2.1 of the PUSAR.[21] This section indicates that Hope Creek participates in the BWR Vessel and Internals Project (BWRVIP) ISP and will comply with the withdrawal schedule specified by this program.

The 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. Additional information necessary to establish the technical basis for, and proposed implementation of, the BWRVIP ISP was provided in letters from the BWRVIP to the NRC dated December 15, 2000, and May 30, 2001. The NRC staff approved the proposed BWRVIP ISP in an SE dated February 1, 2002. The proposed ISP was consolidated into an approved topical report designated as BWRVIP-86-A, "Updated BWR ISP Implementation Plan," and found acceptable per NRC letter dated December 16, 2002. However, the NRC staff's SE required that plant-specific information be provided by BWR licensees who wish to implement the BWRVIP ISP for their facilities. The plant-specific information must demonstrate that each reactor has an adequate dosimetry program and that there is an adequate arrangement for sharing data between plants. In an amendment request dated December 23, 2002,[22] as supplemented by letter dated August 14, 2003,[23] the licensee addressed the Hope Creek plant-specific information required in the NRC staff's February 1, 2002, BWRVIP ISP SE. The NRC staff approved the amendment request in a letter dated July 23, 2004 (Hope Creek Amendment No. 151).[24]

In the SE for Hope Creek Amendment No. 151, the NRC staff evaluated the plant-specific information provided by the licensee to demonstrate the BWRVIP ISP can be implemented at Hope Creek. The NRC staff concluded that the plant-specific information demonstrated has an acceptable withdrawal schedule, adequate dosimetry program and an adequate arrangement for sharing data between plants. Since the licensee has provided the plant-specific information requested in the NRC staff's SE for the proposed BWRVIP ISP, the licensee has demonstrated the compliance of Hope Creek with the ISP requirements of Appendix H to 10 CFR Part 50.

In Section 3.2.1 of the PUSAR, the licensee indicated that the ISP specifies that Hope Creek will remove the next capsule when its fluence equals the reactor vessel 1/4 thickness (T) end of license fluence. Under current licensed thermal power conditions, the ISP estimated this fluence to occur at 22 effective full power years (EFPY). In addition, the licensee states that the withdrawal schedule is not changed by the Hope Creek EPU. However, under Hope Creek EPU operating conditions, the licensee estimates that this (1/4T end of license fluence) will occur at approximately 23 EFPY with EPU in lieu of 22 EFPY at EPU condition (as currently stated in BWRVIP-86-A, Tables 4-4 and 4-5).

In a supplemental letter dated March 13, 2007,[25] the licensee clarified that the change in EFPY was due to a change in the projected neutron fluence at the 1/4T location at end-of-license from

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[21] Attachment 4, page 3-3 of PSEG Letter (LR-N06-0286) to NRC dated September 18, 2006, "Request for License Amendment Extended Power Uprate, Hope Creek Generating Station Facility, Operating License NPF-57, Docket No. 50-354" ADAMS Accession No. ML062680451
[22] ADAMS Accession No. ML023650558
[23] ADAMS Accession No. ML032370148
[24] ADAMS Accession No. ML033230591
[25] PSEG Letter (LR-N-07-0035) to NRC dated March 13, 2007, "Response to Request for Additional Information - Request for License Amendment – Extended Power Uprate" ADAMS Accession No. ML070790508

7.5×10^{17} neutrons per centimeter squared (n/cm^2) (neutron energy (E)> 1 mega electronvolt (MeV)) to 7.6×10^{17} n/cm^2 (E > 1 MeV). This change was due to the licensee's recalculation of the reactor vessel (RV) flux and capsule flux under CPPU conditions using a methodology consistent with Regulatory Guide (RG) 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence." This recalculation also provided a more accurate estimate of the capsule flux during the pre-EPU operating period. The pre-EPU flux was recalculated to be 9.4×10^8 n/cm^2-sec in lieu of 7.6×10^8 n/cm^2-sec (currently used in BWRVIP-86-A).

The withdrawal schedules for the capsules are based on the projected neutron fluence values. Generally, conservative values are used to ensure that neutron embrittlement is adequately monitored during normal operation. In this case, the projected pre-EPU fluence value allows the capsule withdrawal at 22 EFPY. With EPU, the licensee proposed to move the schedule to 23 EFPY.

Based on these new flux values, the licensee stated that if Hope Creek operated for 12 EFPY at original power level and 3 EFPY at the 1.4 percent power uprate, the pre-EPU fluence would be 4.46×10^{17} n/cm^2 (E > 1 MeV). Hope Creek could then operate at proposed EPU conditions for an additional 7.77 EFPY, accumulating an additional fluence of 3.14×10^{17} n/cm^2 (E > 1 MeV) before the capsule would be required to be withdrawn. Therefore, the total combined EFPY is approximately 23 EFPY with EPU in lieu of 22 EFPY with EPU currently stated in BWRVIP-86-A. The licensee stated in its March 13, 2007, letter that upon NRC approval of the Hope Creek EPU, the licensee will inform the BWRVIP in accordance with BWRVIP-86-A. The NRC staff notes that BWRVIP-86-A states that the ISP withdrawal schedule will be re-evaluated periodically based on new information such as updated fluence evaluations, and any changes to the withdrawal schedule will be submitted to the NRC for approval prior to implementation. The NRC staff considers the licensee's response acceptable since the licensee will provide this information (fluence re-evaluation) to the BWRVIP, and any changes to the withdrawal schedule will be submitted to the NRC by the BWRVIP for approval.

As part of the proposed implementation of the BWRVIP ISP, one capsule was removed from the RV after 6.01 EFPY of operation and tested. The remaining two capsules have been in the reactor vessel since plant startup, and the licensee will remove the next capsule at 23 EFPY with EPU of operation, which is equivalent to 1/4T end of life (EOL) fluence. As indicated in the test matrix of BWRVIP-86-A, RV weld and plate surveillance materials from Hope Creek will only be representative of the limiting plate and weld material for the Hope Creek reactor vessel. The fluence value with EPU at 32 EFPY is provided here and the withdrawal schedule is not changed. The peak 1/4T neutron fluence at 32 EFPY for EPU operating conditions for the limiting Hope Creek reactor vessel material at the end of the current Hope Creek license term is 3.7×10^{17} n/cm^2 (E > 1 MeV). Since this fluence value is less than that projected to be received by the representative surveillance materials, the withdrawal schedule of the BWRVIP ISP will continue to provide adequate surveillance data to monitor the impact of neutron radiation on the Hope Creek reactor vessel at EPU operating conditions.

Appendix H of 10 CFR Part 50 requires that an ISP used as a basis for a licensee-implemented reactor vessel surveillance program be reviewed and approved by the NRC staff. The ISP to be used by the applicant is a program that was developed by the BWRVIP. The licensee will apply the BWRVIP ISP as the method by which the Hope Creek reactor vessel will comply with the requirements of 10 CFR Part 50, Appendix H. The BWRVIP ISP identifies capsules that must be tested to monitor neutron radiation embrittlement for all licensees participating in the ISP, and identifies capsules that need not be tested (standby capsules). These untested capsules were originally part of the licensee's plant-specific surveillance program and have received significant amounts of neutron radiation. The remaining capsule is designated a standby capsule in the Hope Creek UFSAR. As addressed in 10 CFR Part 50, Appendix H, Section III (C)(1)(d) and in the staff-approved BWRVIP ISP, maintaining adequate contingencies to support potential changes to the program is an important part of any ISP. It should be noted that the BWRVIP considers the standby Hope Creek surveillance capsule to be a license renewal candidate for the ISP as documented in BWRVIP-116, "BWR Vessel and Internals Project Integrated Surveillance Program (ISP) Implementation for License Renewal." In response to an NRC request for additional information (RAI), the licensee confirmed in its March 13, 2007,[26] letter that the third surveillance capsule will continue to be designated as a "standby" capsule in the Hope Creek UFSAR, Section 5.3.1.6.1, and therefore will continue to reside in the reactor vessel and be tested in accordance with the ISP. Based on the licensee's March 13, 2007, letter and Section 5.3.1.6.1 of the Hope Creek UFSAR, the NRC staff concludes that the licensee satisfies the contingency of 10 CFR Part 50, Appendix H, Section III (C)(1)(d).

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed Hope Creek EPU on the reactor vessel surveillance withdrawal schedule and concludes that the licensee has adequately addressed changes in neutron fluence and their effects on the schedule. The NRC staff further concludes that the reactor vessel capsule withdrawal schedule is appropriate to ensure that the material surveillance program will continue to meet the requirements of 10 CFR Part 50 Appendix H, and 10 CFR 50.60, and will provide the licensee with information to ensure continued compliance with GDC-14, 31 and 34 following implementation of the proposed Hope Creek EPU. Therefore, the NRC staff finds the proposed Hope Creek EPU acceptable with respect to the reactor vessel material surveillance program.

2.1.2 Pressure-Temperature Limits and Upper-Shelf Energy

Regulatory Evaluation

Pressure-temperature (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 P-T limits methodology and the calculations for the number of EFPY specified for the proposed Hope Creek EPU, considering neutron embrittlement effects and using linear elastic fracture mechanics. The NRC's acceptance criteria for P-T limits 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-31, insofar as it requires that the RCPB be designed with margin sufficient to assure that, under specified conditions, it will behave in a non-brittle manner and the probability of a rapidly propagating fracture is minimized; (3) 10 CFR Part 50, Appendix G, which specifies fracture toughness requirements for ferritic components of the RCPB; and (4) 10 CFR 50.60, which requires compliance with the requirements of 10 CFR Part 50, Appendix G. Specific review criteria for

[26] PSEG Letter (LR-N-07-0035) to NRC dated March 13, 2007, "Response to Request for Additional Information - Request for License Amendment – Extended Power Uprate" ADAMS Accession No. ML070790508

the Hope Creek EPU are contained in SRP Section 5.3.2 and other guidance provided in Matrix 1 of Power Uprate Review Standard RS-001.[27]

Technical Evaluation

The ¼ T fluence is the fluence value at ¼ T from the Inside Diameter (ID) of the vessel with T being the vessel thickness. The ¼ T fluence is used for the evaluation of Pressure – Temperature (P – T) curves and Upper Shelf Energy (USE). The ¼ T fluence includes EPU conditions.

Upper-Shelf Energy (USE) Value Calculations

Appendix G of 10 CFR Part 50 provides the NRC's criteria for maintaining acceptable levels of USE for the reactor vessel beltline materials of operating reactors throughout the licensed lives of the facilities. The rule requires reactor vessel beltline materials to have a minimum USE value of 75 foot-pound force (ft-lb) in the unirradiated condition, and to maintain a minimum USE value above 50 ft-lb throughout the life of the facility, unless it can be demonstrated through analyses that lower values of USE would provide acceptable margins of safety against fracture equivalent to those required by Appendix G of Section XI to the 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 reactor vessel surveillance capsule data that are reported through implementation of a plant's 10 CFR Part 50, Appendix H reactor vessel materials surveillance program.

The licensee for Hope Creek discussed the impact of the Hope Creek EPU on the Charpy USE values for the reactor vessel beltline materials in Section 3.2.1 of the PUSAR.[28] Table 3-2, "Hope Creek Upper Shelf Energy - 40 Year Life (32 EFPY)," pp 3-35 of the Hope Creek PUSAR, indicated that the projected Charpy USE for the limiting plate (intermediate shell plate, heat 5K3025) is 60 ft-lbs, and the projected Charpy USE for the limiting weld (intermediate-lower shell-to-intermediate shell circumferential submerged arc weld, heat D55733) is 60 ft-lbs. However, the NRC staff noted that in Table 3-2, heat 10024/1 for the low-pressure coolant injection (LPCI) nozzle forging specifies a copper content of 0.15 percent. In addition, the Hope Creek UFSAR, Appendix 5A, Tables 5A-5 and 5A-19 specifies a copper content of 0.14, while the NRC Reactor Vessel Integrity Database (RVID) specifies a copper content of 0.35 percent for the LPCI forging. In response to an RAI, the licensee, in its letter dated March 13, 2007,[29] confirmed that for heat 10024/1, the copper content is 0.14 percent. This is based on the General Electric Report GE-NE-523-A164-1294R1, Tables 7-2 and 7-3. The NRC staff confirmed that the copper content is 0.14 percent based on the report and will use the reported value to update the RVID copper value for this heat of material.

RG 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," has two methods for determining the percent reduction in Charpy USE. In Position 1.2, the percent reduction in Charpy USE is determined from Figure 2 in RG 1.99, Revision 2, which is based on the neutron fluence and the amount of copper in the material. In the second method, identified as Position

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[27] ADAMS Accession No. ML033640024

[28] Attachment 4, page 3-3 of PSEG Letter (LR-N06-0286) to NRC dated September 18, 2006, "Request for License Amendment Extended Power Uprate, Hope Creek Generating Station Facility, Operating License NPF-57, Docket No. 50-354" ADAMS Accession No. ML062680451

[29] PSEG Letter (LR-N-07-0035) to NRC dated March 13, 2007, "Response to Request for Additional Information - Request for License Amendment – Extended Power Uprate" ADAMS Accession No. ML070790508

2.2, the percent reduction in Charpy USE is determined from surveillance data. RG 1.99, Revision 2 indicates surveillance data may be used for determining the Charpy USE when two or more credible surveillance data sets become available from the reactor. Since only one data set is presently available from the Hope Creek surveillance weld and surveillance plate, RG 1.99, Revision 2 would recommend that the Charpy USE be determined using Position 1.2. Using Figure 2 in RG 1.99, Revision 2, the staff determined that the percent reduction in Charpy USE based on an EOL neutron fluence of 5.3×10^{17} n/cm^2 (E > 1 MeV) was 11.1 percent for the plate material and the submerged arc weld material. Using the unirradiated values for the Charpy USE for the plate (75 ft-lbs) and the weld (68 ft-lbs) and the percent reduction determined using Figure 2 in RG 1.99, Revision 2, the Charpy USE at a neutron fluence of 5.3×10^{17} n/cm^2 (E > 1 MeV) is 66 ft-lb for the plate material and 60 ft-lb for the weld material. Since both the weld metal and plate material are projected to have Charpy USE greater than 50 ft-lb at EOL under Hope Creek EPU operating conditions, the reactor vessel materials satisfy the requirements of 10 CFR Part 50, Appendix G. As discussed in Section 2.1.1 of this SE, the surveillance data from Hope Creek (under the BWRVIP ISP) will be used to monitor the impact of neutron radiation on the Hope Creek beltline materials. In accordance with 10 CFR Part 50, Appendix G, the licensee is required to re-evaluate the impact of neutron radiation on Charpy USE when its surveillance data becomes available.

Pressure-Temperature Limit Calculations

Section IV.A.2 of 10 CFR Part 50, Appendix G 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 the ASME Code, Section XI, Appendix G were used to calculate the P-T limits. The regulation also requires that the P-T limit calculations account for the effects of neutron irradiation on the P-T limit values for the reactor vessel beltline materials and incorporate any relevant reactor vessel surveillance capsule data that are required to be reported as part of the licensee's implementation of its 10 CFR Part 50, Appendix H reactor vessel materials surveillance program.

Section 3.2.1 of the PUSAR[30] indicates that the P-T limit curves contained in the technical specifications (TSs) remain bounding for Hope Creek EPU operating conditions and were approved in Hope Creek Amendment No. 157[31] dated November 1, 2004. Table 3-1 of the PUSAR (page 3-34), indicated that the adjusted reference temperature (ART) for the limiting material (intermediate shell plate, heat 5K3025) is 75 °F at a 1/4T fluence value of 3.7×10^{17} n/cm^2 (E > 1 MeV). This is consistent with the value referenced in the staff's November 1, 2004, safety evaluation which approved the P-T limit curves for 32 EFPY under Hope Creek EPU operating conditions. Therefore, the NRC staff agrees that the P-T limit curves contained in the TSs remain bounding for Hope Creek EPU operating conditions.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed Hope Creek EPU on the USE values for the reactor vessel 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 Hope Creek reactor vessel beltline materials and the P-T

[30] Attachment 4, page 3-3 of PSEG Letter (LR-N06-0286) to NRC dated September 18, 2006, "Request for License Amendment Extended Power Uprate, Hope Creek Generating Station Facility, Operating License NPF-57, Docket No. 50-354" ADAMS Accession No. ML062680451
[31] ADAMS Accession No. ML042050079

limits for the plant. The staff concludes that the Hope Creek beltline materials will continue to have acceptable USE values, as mandated by 10 CFR Part 50, Appendix G, through the expiration of the current operation license for the facility. The NRC staff further concludes that the licensee has demonstrated the validity of the current P-T limits for the proposed Hope Creek EPU operating conditions. Based on this, the NRC staff concludes that the proposed P-T limits will continue to meet the requirements of 10 CFR Part 50, Appendix G, and 10 CFR 50.60 and will enable the licensee to comply with GDC-14, and 31 following implementation of the proposed Hope Creek EPU. Therefore, the NRC staff finds the proposed Hope Creek EPU acceptable with respect to the TS P-T limits.

2.1.3 Reactor Internal and Core Support Materials

Regulatory Evaluation

The reactor 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 reactor internal and core support materials are based on GDC-1 and 10 CFR 50.55a for material specifications, controls on welding, and inspection of reactor internals and core supports. Specific review criteria for the Hope Creek EPU are contained in SRP Section 4.5.2 and BWRVIP-26, "BWR Top Guide Inspection and Flaw Evaluation Guidelines," and Matrix 1 of Power Uprate Review Standard RS-001.[32]

Technical Evaluation

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

- Crack initiation and growth due to stress-corrosion cracking (SCC), intergranular stress-corrosion cracking (IGSCC) and irradiation-assisted stress-corrosion cracking (IASCC);
- Crack initiation and growth due to flow-induced vibration;
- Cumulative fatigue damage; and
- Loss of fracture toughness due to thermal aging and neutron embrittlement.

Cumulative fatigue damage and crack initiation and growth due to FIV are discussed in Section 2.2.3 of this SE. Crack initiation and growth and loss of fracture toughness due to thermal aging and neutron embrittlement are managed through the inservice inspection (ISI) program that conforms to the requirements of 10 CFR 50.55a and the BWRVIP program. The BWRVIP inspection program supplements the ISI program required by 10 CFR 50.55a. The BWRVIP program has been reviewed and approved by the NRC.

Section 10.7, "Plant Life," of the PUSAR[33] identifies irradiation-assisted stress-corrosion cracking (IASCC) as a degradation mechanism influenced by increases in neutron fluence. The

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[32] ADAMS Accession No. ML033640024

[33] Attachment 4, page 10-33 of PSEG Letter (LR-N06-0286) to NRC dated September 18, 2006, "Request for License Amendment Extended Power Uprate, Hope Creek Generating Station Facility, Operating License NPF-57, Docket No. 50-354" ADAMS Accession No. ML062680451

licensee also stated that Hope Creek has a procedurally-controlled program that is consistent with the BWRVIP documents for the augmented nondestructive examination of selected reactor pressure vessel (RPV) internal components (core spray (CS) piping, CS spargers, core shroud and core shroud supports, jet pumps and associated components, top guide, lower plenum, vessel inside diameter (ID) attachment welds, and FW sparger) in order to ensure their continued structural integrity. In addition, only two components are predicted to exceed the BWRVIP-26 report threshold fluence level of 5×10^{20} n/cm^2 (E > 1 MeV), which are the top guide and the shroud. The licensee confirmed in its supplemental letter dated March 13, 2007,[34] that the core plate, in-core flux monitoring guide tubes, and control rod guide tubes were considered in the determination of which components exceed the BWRVIP-26 threshold fluence, but were found to be below 5×10^{20} n/cm^2 (E > 1 MeV). However, the licensee noted that the upper portion of the in-core flux monitoring dry tube assemblies are located in the reactor core, and therefore assumed to exceed the BWRVIP-26 threshold fluence. The licensee will consider the in-core flux monitoring dry tube assemblies for augmented nondestructive examinations as discussed below.

In addition, Hope Creek injects hydrogen in the primary system for IGSCC mitigation in the recirculation piping. Reactor water chemistry conditions are maintained consistent with established Electric Power Research Institute (EPRI) and established industry guidelines. However, the NRC staff notes that reactor vessel internals may also be susceptible to SCC, and IGSCC. In response to the NRC staff's RAI, the licensee stated in its letter dated March 13, 2007, that during RFO 13 (spring 2006), Hope Creek implemented noble metal chemical addition (NMCA) as its IGSCC mitigation strategy for the RV internals. Hope Creek is considered a Category 3.a type plant in accordance with Table 2-6 of BWRVIP-130, "BWR Water Chemistry Guidelines." The NRC staff acknowledges that the licensee uses water chemistry to mitigate IGSCC and SCC for the RV internals as recommended by the appropriate BWRVIP guidelines.

Since CPPU conditions do not significantly increase the potential for degradation, the NRC staff concludes that the current inspection program is acceptable for all reactor vessel internals components except for those that will exceed the threshold fluence level for IASCC (5×10^{20} n/cm^2 (E > 1 MeV)), which are discussed below.

Top Guide

Note 1 in Matrix 1 of Section 2.1 of RS-001,[35] indicates that guidance on the neutron irradiation-related threshold for inspection for IASCC in BWRs is in BWRVIP report BWRVIP-26. The NRC staff's SE for BWRVIP-26 dated December 7, 2000, states that the threshold fluence level for IASCC is 5×10^{20} n/cm^2 (E > 1 MeV).

In response to the NRC staff's RAI, the licensee provided the following inspection program for the top guide in its letter dated March 13, 2007

> The top guide inspection program is BWRVIP-26-A. Hope Creek utilizes wedges to provide lateral support and to increase the seismic margin of the top guide. For this configuration, BWRVIP-26-A, requires the inspection of the top guide hold-down

[34] ADAMS Accession No. ML070790508
[35] NRC Review Standard RS-01, "Review Standard for Extended Power Uprates," Revision 0 (December 2003) ADAMS Accession No. ML033640024

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 intertied such that a large number of complete separations would need to occur before control rod insertion would be affected."

The NRC staff is concerned that multiple failures of the top guide grid beams are possible when the IASCC threshold fluence is exceeded. BWRVIP-26-A acknowledges that, while there is no safety concern from a single grid beam failure, multiple grid beam failures would be a safety concern, as they would compromise the safe shutdown of the reactor.

For example, according to BWRVIP-26-A, multiple cracks have been observed in the top guide beams at another BWR facility. In addition, multiple failures have occurred in other components that have exceeded the threshold fluence for IASCC, such as baffle-former bolts in PWRs.

The NRC staff also notes that the BWRVIP has been informed of this issue by an NRC letter dated June 10, 2003.[36] 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 an inspection program for top guide beams that exceed the IASCC threshold fluence for all BWRs should be developed by the BWRVIP to ensure that all BWRs can meet the requirements of 10 CFR Part 54 (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 would be exceeded during the extended period of operation. However, the NRC now has information that some plants, such as Hope Creek, 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 on resolving this issue generically, but until then, a site-specific inspection program is necessary to manage the effects of IASCC in the top guide.

Matrix 1 of Power Uprate Review Standard RS-001,[37] specifies that the NRC's acceptance criteria for reactor internal 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 is required by GDC-1 to be supplemented.

Until there is more detailed guidance regarding the inspections of the top guide beams or the issue is resolved by the BWRVIP generically, the staff has imposed the following license condition to preclude the loss of component intended function, as required by GDC-1:

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[36] NRC Letter to BWRVIP, Carl Terry, Constellation Energy, dated June 10, 2003, regarding BWR Top Guide Inspection and Flaw Evaluation Guidelines. ADAMS Accession No. ML031611051

[37] NRC Review Standard RS-01, "Review Standard for Extended Power Uprates," Revision 0 (December 2003). ADAMS Accession No. ML033640024

> Enhanced visual testing (EVT-1) of the top guide grid beams will be performed in accordance with GE [Services Information Letter] (SIL) 554 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 twelve years, and 5 percent 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 RFO following Hope Creek EPU operation.

The NRC staff concludes that the proposed program, with the above license condition, is reasonable and provides an acceptable means to manage the potential for IASCC and IGSCC of the Hope Creek top guide grid beams.

Core Shroud

In response to the NRC staff's RAI, the licensee provided the following inspection program for the core shroud in its letter dated March 13, 2007.[38]

> The shroud inspection program is BWRVIP-76, "Core Shroud Inspection and Flaw Evaluation Guidelines." This document defines the scope, sample size, inspection method, frequency of examination, and flaw evaluations for the shroud. Currently, the Hope Creek shroud is classified as Category B per BWRVIP-76 since no flaws were found during the last ultrasonic (UT) inspection of welds H3, H4, H5, and H7. Per BWRVIP-76 re-inspection is required in 10 years and the scope will be based on the results of the next inspection. If flaws are found during these inspections, a BWRVIP-76 evaluation will be made considering crack growth rate based on fluence and fracture toughness based on fluence. This evaluation will verify structural integrity and define inspection frequency.

Since the inspection program has inspected, and will continue to inspect, the core shroud in accordance with the guidelines of BWRVIP-76 with no deviations, the NRC staff concludes that the proposed program is reasonable to manage the potential for IASCC and IGSCC of the core shroud.

In-Core Flux Monitoring Dry Tube Assembly

In response to the NRC staff's RAI, the licensee provided the following inspection program for the in-core flux monitoring dry tube assembly in its letter dated March 13, 2007:

> 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. 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 Hope Creek inspection program for dry tubes is based on GE SIL 409, revision 2. Hope Creek replaced the dry tube assemblies in 2000. The upper two feet of the dry tube assemblies will be inspected visually within 20 years of the replacement date and every two outages thereafter. The replacement dry tubes are constructed with IASCC-resistant material.

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[38] ADAMS Accession No. ML070790508

Since the licensee has replaced the in-core flux monitoring dry tube assemblies in 2000, the occurrence of IASCC has been minimized. In addition, the licensee continues to inspect in accordance with the ISI program and the augmented inspections in accordance with industry guidelines to ensure that any cracking will be identified in a timely manner so that proper repair and other mitigation techniques can be implemented to restore the function of the in-core flux monitoring dry tube assemblies.

The NRC staff concludes that the proposed program is reasonable to manage the potential for IASCC of the in-core flux monitoring dry tube assemblies.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed Hope Creek EPU on the susceptibility of reactor internal and core support materials to known degradation mechanisms and concludes, with the addition of the above license condition for inspecting the top guide beams, that the licensee has identified appropriate degradation management programs to address the effects of changes in operating temperature and neutron fluence on the integrity of reactor internal and core support materials. The NRC staff further concludes that the licensee has demonstrated that the reactor internal and core support materials will continue to be acceptable and will continue to meet the requirements of draft GDC-1 and 10 CFR 50.55a with respect to material specifications, welding controls, and inspection following implementation of the proposed Hope Creek EPU. Therefore, the NRC staff finds the proposed Hope Creek EPU acceptable with respect to reactor internal and core support materials.

2.1.4 Reactor Coolant Pressure Boundary Materials

Regulatory Evaluation

The RCPB material defines the boundary of systems and components containing the high-pressure 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 staff's acceptance criteria for RCPB materials are based on: (1) 10 CFR 50.55a and GDC-1, insofar as they require that SSCs important to safety be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC-4, insofar as it requires that SSC 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 non-brittle manner and the probability of a rapidly propagating fracture is minimized; and (5) 10 CFR Part 50, Appendix G, which specifies fracture toughness requirements for ferritic components of the RCPB. Specific review criteria for the Hope Creek EPU are contained in SRP Section 5.2.3 and other guidance provided in Matrix 1 of Power Uprate Review Standard RS-001.[39] Additional information regarding intergranular stress-corrosion cracking of dissimilar metal welds and associated inspection programs is contained in Generic Letter 88-01 and Information Notice 00-17. Additional review

[39] ADAMS Accession No. ML033640024

guidance for thermal embrittlement of cast austenitic stainless steel components is contained in a letter from C. Grimes, NRC, to D. Walters, Nuclear Energy Institute (NEI) dated May 19, 2000.[40]

Technical Evaluation

The Hope Creek RCPB piping was evaluated for EPU at CPPU conditions as follows: (1) reactor recirculation system (RRS); (2) control rod drive system (CRDS); (3) residual heat removal (RHR) system; (4) LPCI system; (5) CS system; (6) standby liquid control system (SLCS); (7) RPV bottom head drain; (8) main steam (MS) system and associated branch piping; (9) FW system; and (10) RCPB portion of the RPV head vent line, safety relief valves (SRVs) discharge piping and MS isolation valves (MSIVs) drain piping. The licensee's evaluation determined that the proposed Hope Creek EPU will not significantly affect the RCPB piping considering the potential changes in temperature, pressure, flow, and mechanical loading resulting from CPPU operation. The staff finds the licensee's conclusion acceptable because the RCPB piping evaluation was performed in accordance with the processes identified in the previously staff approved CLTR,[41] ELTR1[42] and in ELTR2.[43]

However, in Section 3.5.1, "Reactor Coolant Pressure Boundary Piping" of the PUSAR,[44] the staff identified an action item which stated that power uprate applicants must identify all other than Category "A" materials, as defined in NUREG-0313, Revision 2 that exist in its RCPB piping, and discuss the adequacy of the augmented inspection programs in light of the power uprate on a plant specific basis.

To evaluate the adequacy of the RCPB piping materials in light of the proposed power uprate for Hope Creek, the NRC staff sent RAI questions in a letter dated February 23, 2007 (ML070460243). Specifically, the NRC staff requested that the licensee: (1) Identify the materials of construction for the RCPB piping/safe-ends. Discuss and explain the affect of the requested power uprate on the RCPB piping/safe-end materials. (2) Identify the RCPB piping/safe-end components that are susceptible to intergranular stress-corrosion cracking (IGSCC). Discuss any augmented inspection programs that have been implemented and the adequacy of the augmented inspection programs in light of the requested Hope Creek 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. Discuss the adequacy of such analysis considering the effect of the Hope Creek EPU on the flaws, and (4) identify the mitigation processes being applied at Hope Creek to reduce the RCPB component's susceptibility to IGSCC, and discuss the effect of the requested Hope Creek EPU on the effectiveness of these mitigation processes. For example, if hydrogen water chemistry (HWC) was applied at the plant, it would be necessary to perform the electrochemical potential (ECP) measurements at the most limiting locations to ensure that the applied hydrogen injection rate is adequate to maintain the effectiveness of HWC since oxygen content in the coolant is expected to increase due to increased radiolysis of water resulting from EPU.

[40] ADAMS Accession No. ML003717179
[41] ADAMS Accession No. ML031190318
[42] ADAMS Accession No. ML003680231
[43] ADAMS Accession No. ML003712826
[44] Attachment 4 of PSEG Letter (LR-N06-0286) to NRC dated September 18, 2006, "Request for License Amendment Extended Power Uprate, Hope Creek Generating Station Facility, Operating License NPF-57, Docket No. 50-354" ADAMS Accession No. ML062680451

In response to the NRC staff's RAI provided in a letter dated March 22, 2007,[45] the licensee stated that Hope Creek was designed, fabricated, and constructed per the guidance in NUREG-0313, Revision 2, so most welds are IGSCC Category A welds which are resistant to IGSCC. However, there are 22 welds that are considered susceptible to IGSCC. These are 18 Category C welds (9 RPV recirculation inlet nozzle to safe end welds, two RPV recirculation outlet nozzle to safe end welds, two CS safe end to safe end extension welds, one RPV CS inlet nozzle to safe end weld, one RPV CRD nozzle to cap weld, one RPV head spray nozzle to flange weld, and two RPV jet pump instrumentation nozzle to safe end), two Category B welds (recirculation to decontamination line weldolets) and two Category E welds (weld overlay repaired welds). Hope Creek's IGSCC augmented inspection program is based on BWRVIP-75-A, "BWR Vessel and Internals Project Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules." The licensee further explained that for IGSCC to occur, three conditions must exist: the existence of a susceptible material, the presence of tensile stresses and the presence of an oxidizing environment. Operation at CPPU conditions will result in somewhat higher pressure, temperature, and flow for some systems comprising portions of the RCPB, but these changes will have negligible effect on the tensile stresses. Therefore, CPPU operation will not affect the material's susceptibility to IGSCC. Operation at a higher power level will result in a slightly higher oxygen generation rate due to radiolysis of water. However, as discussed later, steps will be taken to ensure that RCPB piping will continue to be mitigated from an oxidizing environment perspective. Since the three conditions that cause IGSCC to occur are essentially unchanged for CPPU conditions, the IGSCC augmented inspection program will remain the same for the Hope Creek EPU.

The licensee stated that Hope Creek has three weld overlay repaired welds (reactor vessel CS nozzle to safe end weld (N5B), reactor vessel recirculation inlet nozzle to safe end weld (N2A), and reactor vessel recirculation inlet nozzle to safe end weld (N2K). The weld overlay repairs were designed to ASME Code Section XI requirements. The CPPU operating conditions have no affect on the overlay repair designs because the changes in pressure, temperature and flow rate resulting from CPPU operation 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 Hope Creek EPU operation.

The licensee stated that several mitigation processes have been applied to Hope Creek to reduce the RCPB component's susceptibility to IGSCC. These include the use of IGSCC resistant materials, application of mechanical stress improvement process (MSIP) and the implementation of HWC with NobleChem. All Category C welds (18) and Category B welds (2) were applied with MSIP. The effectiveness of MSIP and IGSCC resistant materials are not affected by the proposed Hope Creek EPU.

A NobleChem application was performed during cycle 13 refueling in April 2006. A mitigation monitoring system including iron, and platinum ECP electrodes, and 24 durability coupons (catalyst loading) was installed in January 2006. A hydrogen benchmark test was conducted following the cycle 13 reactor start-up in May 2006. All secondary parameters were also benchmarked to provide correlation with measured ECP. The molar ratio data based on EPRI Radiolysis/ECP Model was used to monitor the ECP condition at the most limiting location in the vessel, currently defined as the upper downcomer. Following the Hope Creek EPU implementation, the licensee will perform a second hydrogen benchmark test to determine the appropriate injection level, and will update the radiolysis/ECP Model and run cases to validate

[45] ADAMS Accession No. ML070930442

molar ratio data. These actions will ensure that the Hope Creek EPU will not affect the HWC controls used for mitigation of IGSCC.

The 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 MSIP, and implementation of HWC with NobleChem at Hope Creek. The staff also finds that the licensee's actions to perform a second hydrogen bench mark test and re-validation of molar ratio data provide adequate assurance that the HWC program implemented at Hope Creek will continue to be effective for mitigation of IGSCC under CPPU operating conditions.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed Hope Creek 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 NRC staff further concludes that the licensee has demonstrated that the RCPB piping materials at Hope Creek will continue to be acceptable following implementation of the proposed Hope Creek EPU and will continue to meet the requirements of GDC-1, GDC-4, GDC-14, GDC-31, 10 CFR Part 50, Appendix G, and 10 CFR 50.55a. Therefore, the NRC staff finds the proposed EPU at Hope Creek acceptable with respect to RCPB piping materials.

2.1.5 Protective Coating Systems (Paints) - Organic Materials

Regulatory Evaluation

Organic paints are protective coating systems that provide a means for protecting the surfaces of facilities and equipment from corrosion and contamination from radionuclides and also provide wear protection during plant operation and maintenance (O&M) 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) 10 CFR 50, Appendix B, 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," for application and performance monitoring guidance of coatings in nuclear power plants. Specific review criteria for the Hope Creek EPU are contained in SRP Section 6.1.2, "Protective Coating Systems (Paints) - Organic Materials," and other guidance provided in Matrix 1 of Power Uprate Review Standard RS-001.[46]

Technical Evaluation

Hope Creek has 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 requirements of RG 1.54 were not imposed on the paint material or application for the NSSS because most of these components were ordered before RG 1.54 was issued. However, according to the Hope Creek UFSAR, Hope Creek complies with the requirements and guidelines of ANSI N101.4-1972, as endorsed and modified

[46] ADAMS Accession No. ML033640024

by RG 1.54. The USFAR also states that most of the NSSS equipment is coated with inorganic zinc primer, the suppression chamber is coated with an immersion phenolic epoxy, and the drywell and exposed structural metal surfaces in the drywell and torus are coated with a modified phenolic epoxy. In its April 30, 2007,[47] RAI response, the licensee confirmed that all of these coatings were qualified in accordance with ANSI N101.2, "Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities."

Also, in the April 30, 2007, letter, 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 CPPU conditions on these activities. New Service Level I coatings applications and repairs to existing coatings are in accordance with plant standards based on ASTM Standard D5144-00, "Standard Guide for Use of Protective Coatings Standards in Nuclear Power Plants." RG 1.54 considers ASTM D5144 a top-level standard that incorporates, by reference, other ASTM standards on personnel, quality assurance, and performance related to coatings applications at nuclear power plants. In addition to its technical standards, the licensee has a procedure for coating application, assessment, and maintenance. The licensee stated that the proposed power uprate would not change these requirements because Service Level I coatings were qualified for conditions that bound the power uprate conditions.

In its letter dated April 30, 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. Qualified coatings on most NSSS equipment, the suppression chamber, the drywell, and exposed metallic structures in the drywell and torus were qualified in accordance with ANSI N101.2. The qualification test conditions of 9.58×10^8 radiation absorbed dose (rad) total integrated dose, 340 °F, and 62 pounds per square inch gauge (psig), are higher than the values of 8.4×10^7 rad, 50.6 psig, and 298 °F corresponding to the conditions in containment following a postulated LOCA at power uprate conditions. Based on the information discussed above, the staff finds the licensee's activities on coatings qualification testing, inspection, and maintenance indicates it will continue to meet the positions of RG 1.54 at power uprate conditions.

In the PUSAR,[48] the licensee provided an estimate of the amount of coating debris that would contribute to the ECCS suction strainer debris loading following a postulated design basis LOCA. The amount is based on LTR NEDO-32686, Rev. 1, "Utility Resolution Guidance for ECCS Suction Strainer Blockage" and includes all of the unqualified coatings 270 lb (122 Kg) and 85 lb (39 Kg) of qualified coatings. In the letter dated April 30, 2007, the licensee confirmed that the amount of debris from qualified coatings is based on the highest value from LTR NEDO-32686, Rev. 1 for combinations of inorganic zinc and epoxy (the predominant coating systems in the Hope Creek containment). The debris estimates are therefore conservative within the range of values approved by the staff in NEDO-32686.

The licensee stated in its September 18, 2006, application, that the zones of influence used to evaluate the amount of coatings debris generated in a postulated design basis LOCA would not be affected by the power uprate. In its letter dated April 30, 2007, the licensee stated that the

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[47] ADAMS Accession No. ML071290559
[48] Attachment 4 of PSEG Letter (LR-N06-0286) to NRC dated September 18, 2006, "Request for License Amendment Extended Power Uprate, Hope Creek Generating Station Facility, Operating License NPF-57, Docket No. 50-354" ADAMS Accession No. ML062680451

calculations of the jet forces resulting from high-energy pipe breaks used parameters (operating pressure, opening area, thrust factor) that are bounding for power uprate conditions. On this basis, the staff agrees with the licensee's conclusion that the proposed power uprate would not affect the amount of coatings debris transported to the suction strainer or the ECCS pump head losses.

In addition to paints, other organic material such as cable insulation can be exposed to DBA conditions which could degrade the material and generate organic gases and hydrogen (through radiolysis, for example). In its April 30, 2007, letter, the licensee explained that the proposed power uprate would not affect existing evaluations of hydrogen and organic gases. With respect to maintaining pH above 7 in a post-LOCA suppression pool environment, the licensee has completed this evaluation for power uprate conditions. With respect to hydrogen gas generation, the licensee stated that evaluation was unnecessary based on a license amendment that eliminates the requirements for hydrogen control systems. Based on this, the staff finds the licensee's treatment of paints and other organic material acceptable with respect to hydrogen generation and contribution to suppression pool pH.

Conclusion

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

2.1.6 Flow-Accelerated Corrosion (FAC)

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 not affected by FAC, and FAC is significantly reduced in components containing even small amounts of chromium or molybdenum. The rates of material loss due to FAC depend on flow velocity, fluid temperature, steam quality, oxygen content, and pH. During plant operation, it is not normally possible to maintain these parameters in a regime that minimizes FAC, and loss of material by FAC can therefore occur. The NRC staff reviewed the effects of the proposed Hope Creek EPU on FAC and the adequacy of the licensee's FAC program to predict the rate of component thinning so that repair or replacement of damaged components could be made before reaching a critical thickness. The licensee's FAC program consists of predicting loss of material using the EPRI 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 Hope Creek FAC program is based on selective component inspections according to guidance in EPRI Report NSAC-202L-R2, "Recommendations for an Effective Flow-Accelerated Corrosion Program," and structural acceptance criteria from the ASME Code. The program includes a plant-specific CHECWORKS FAC model to predict corrosion rate and remaining service life for components containing single- and two-phase fluids. In its letter dated April 30, 2007,[49] the licensee stated that selection of inspection locations is based on the CHECWORKS model, industry experience, and experience at Hope Creek, re-inspections based on the previously measured thinning rate, engineering judgment, and evaluation of susceptibility and failure consequences for components that cannot be modeled in CHECWORKS. In addition, the licensee's FAC program provides for inspections to detect other forms of flow-related thinning, such as liquid droplet impingement and cavitation.

The CHECWORKS program is used to model and evaluate piping systems in order to focus inspection resources on the locations most susceptible to degradation. This 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. At a minimum, the CHECWORKS FAC model is updated after each RFO.

The licensee summarized the inspection and evaluation process in its letter dated April 30, 2007. Component thickness is measured using ultrasonic testing (UT), which is judged the most suitable technique by EPRI Report NSAC-202L-R2 for measuring the remaining wall thickness. Grid size and layout is specified according to EPRI Report NSAC-202L-R2, including grid-size reduction where significant thinning is measured. Inspection results are evaluated according to the methods described in EPRI Report NSAC-202L-R2 using wall thickness criteria calculated by the licensee's mechanical design group. The evaluation methods use the measured thickness, minimum acceptable thickness, and corrosion rate to determine remaining life and the next scheduled inspection (outage prior to reaching minimum allowable thickness). Components are repaired or replaced if any of the plant's design requirements are not met.

The licensee stated in its September 18, 2006, application[50] that the criteria for selecting components for inspection will not change as a result of the Hope Creek EPU. Parameters that influence FAC include: temperature, moisture content, water chemistry (including dissolved oxygen), flow geometry and velocity, and material (alloy) composition. The licensee stated that the values of these parameters will change in many locations, but will remain within the range that can be modeled in the Hope Creek CHECWORKS program. In its letter dated May 18, 2007,[51] the licensee provided a comparison of pre-Hope Creek EPU and projected post-Hope Creek EPU corrosion rates for components with the highest post-Hope Creek EPU corrosion rates. This comparison was performed following the fall 2002 inspection using the input data from that outage and a hypothetical 20 percent power increase. The NRC staff finds the amount of the corrosion rate increase (approximately 10 percent to 25 percent from the licensee's May 18, 2007, letter) reasonable for the corresponding changes in operating conditions. At the time of the licensee's response, the CHECWORKS model was being updated for the fall 2007 inspection scope based on the proposed 15 percent power uprate. Based on

[49] ADAMS Accession No. ML071290559
[50] ADAMS Accession No. ML062680451
[51] ADAMS Accession No. ML071500294

its modeling, the licensee determined that additional inspection locations would be added in portions of the condensate, FW, heater drain, and seal steam systems. In its letter dated April 30, 2007,[52] the licensee stated that the components identified at that time included two FW trains downstream of the high-pressure FW heaters, the seal steam system, and drain lines from two of the FW heaters.

The licensee discussed the small bore piping program in its letter dated April 30, 2007. A small-bore piping program is currently being developed based on the guidelines in EPRI Report NSAC-202L-R2. Small-bore piping is included in the group of components than are susceptible to FAC but are not suited to modeling for FAC. These components are ranked according to the consequences of failure and FAC susceptibility based on assumed operating conditions. Small bore piping with greater than minimal consequences of failure is being replaced with materials not susceptible to FAC. Small-bore piping with susceptibility less than high will be inspected and monitored. The staff finds this approach consistent with the EPRI Report guidance cited above.

Conclusion

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

2.1.7 Reactor Water Cleanup (RWCU) 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 operating 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, insofar as it requires that the plant design include means to control the release of radioactive effluents; and (3) GDC-61, insofar as it requires that systems that contain radioactivity be designed with appropriate confinement. Specific review criteria for the Hope Creek EPU are contained in SRP Section 5.4.8 and other guidance provided in Matrix 1 of Power Uprate Review Standard RS-001.[53]

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[52] ADAMS Accession No. ML071290559
[53] ADAMS Accession No. ML033640024

Technical Evaluation

Since the RWCU system continuously withdraws a portion of the reactor water, the 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,[54] concluded that changes to the system resulting from the Hope Creek EPU would be negligible and insignificant to the system performance. These changes include a decrease in inlet temperature and increase in system pressure. The licensee provided the magnitude of these changes in its letter dated March 22, 2007.[55] The decreases in the inlet and outlet temperatures are less than 1 °F. The expected increase in outlet pressure is from 1049 psig to 1063 psig, while the limiting system design pressure is 1400 psig (main cleanup recirculation pumps). Based on these values, the staff agrees the changes are insignificant with respect to system performance.

Under the proposed Hope Creek EPU operating conditions, the MS flow rate at normal operating conditions would increase from about 14.4 million pounds per hour (Mlb/hr) to about 16.9 Mlb/hr. The present flow rate through the RWCU system is 0.133 Mlb/hr. If the present RWCU system flow rate is not changed, the percentage of MS flow routed to the RWCU system would decrease from about 0.9 percent to 0.8 percent. The criteria in SRP Section 5.4.8 are that the RWCU system flow rate should be approximately 1 percent of the MS flow rate. (The system design maximum is 0.148 Mlb/hr, slightly higher than 1 percent of the steam flow rate at CLTP). The licensee evaluated the RWCU system and concluded that it could continue to perform its impurity removal function at 0.133 Mlb/hr because changes in the system will be negligible. The NRC staff's evaluation of these changes is discussed below.

According to the September 18, 2006, application[56], the licensee's calculations indicated the higher FW flow rate will increase the reactor water iron concentration from about 16 parts per billion (ppb) to about 19 ppb, and the reactor water conductivity will increase from 0.068 micro-mho per centimeter (μmho/cm) to 0.071 μmho/cm. The conductivity increase is attributed mainly to the iron increase. However, the licensee's March 22, 2007, letter, indicated reactor water iron levels have decreased as a result of a water chemistry change that was not yet reflected in the Hope Creek EPU application. From November 2006 to February 2007 the total iron level in the reactor water stabilized at about 9 ppb, and the licensee does not expect it to change as a result of the CPPU because it is controlled primarily by chemical addition to the FW. The increase in the amount of iron passing through the RWCU system due to the higher FW flow will make it necessary to backwash the RWCU system filter/demineralizer and replace the demineralizer resin more frequently to maintain reactor water chemistry. The backwash interval is expected to decrease by about 10 percent (about 10 days). Because past chemistry changes have demonstrated the ability to accommodate this amount of change, the licensee concluded the corresponding increase in liquid and solid radwaste will not challenge the system capacity.

In the September 18, 2006, application, the licensee stated that due to changes in operating conditions, some containment isolation valves would remain capable of performing their isolation function but have reduced operating margins. In its letter dated March 22, 2007, the licensee indicated the reduction in operating margin would be minimal and would not affect the

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[54] Attachment 4 to PSEG Letter (LR-N06-0286) to NRC dated September 18, 2006, "Request for License Amendment Extended Power Uprate, Hope Creek Generating Station Facility, Operating License NPF-57, Docket No. 50-354" ADAMS Accession No. ML062680451

[55] ADAMS Accession No. ML070930442

[56] ADAMS Accession No. ML062680451

isolation capability of the RWCU system. Because the effects of CPPU on the system are small, no changes to process control instrumentation or setpoints are expected. Based on the above discussion, the staff concurs that the changes introduced to the RWCS operating parameters by the proposed Hope Creek EPU will be small and will not significantly affect the performance of the system's intended functions.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed Hope Creek EPU on the RWCU system and concludes that change in the reactor coolant impurity levels and changes to the RWCU system operating pressure will have minor effects on Hope Creek plant operations and on the RWCU system operation. The NRC staff further concludes that the licensee has demonstrated that the RWCU system will continue to meet the requirements of GDC-14, GDC-60, and GDC-61. Therefore, the NRC staff finds the proposed Hope Creek EPU acceptable with respect to the minor changes in the Hope Creek RWCU system.

2.2 Mechanical and Civil Engineering

2.2.1 Pipe Rupture Locations and Associated Dynamic Effects

Regulatory Evaluation

SSCs important to safety could be impacted by the pipe-whip dynamic effects of a pipe rupture. The NRC staff conducted a review of pipe rupture analyses to ensure that SSCs important to safety are adequately protected from the effects of pipe ruptures. The NRC staff's review covered: (1) the implementation of criteria for defining pipe break and crack locations and configurations; (2) the implementation of criteria dealing with special features, such as augmented ISI programs or the use of special protective devices such as pipe-whip restraints; (3) pipe-whip dynamic analyses and results, including the jet thrust and impingement forcing functions and pipe-whip dynamic effects; and (4) the design adequacy of supports for SSCs provided to ensure that the intended design functions of the SSCs will not be impaired to an unacceptable level as a result of pipe-whip or jet impingement loadings. The NRC staff's review focused on the effects that the proposed EPU may have on items (1) thru (4) above. The NRC's acceptance criteria are based on GDC-4, which requires SSCs important to safety to be designed to accommodate the dynamic effects of a postulated pipe rupture. Specific review criteria are contained in SRP Section 3.6.2 and other guidance provided in Matrix 1 of Power Uprate Review Standard RS-001.[57]

Technical Evaluation

The licensee's review of the effects of CPPU on the postulated pipe rupture locations and associated dynamic effects for HCGS is documented in the PUSAR.[58] The licensee's approach to CPPU is documented in NEDC-33004P-A,[59] which maintains the current plant maximum normal operating reactor dome pressure for CPPU. The original design basis for the HCGS RCPB includes postulated pipe breaks in all high energy fluid system piping greater than 1 inch in diameter.

The licensee notes that the majority of the RCPB piping systems experience no increase in pressure, temperature, flow or mechanical loading for CPPU, except for the MS and FW piping systems, which exhibit flow increases of about 16.4 percent. The licensee indicates that seismic, hydrodynamic, safety relief valve discharge inertia loads are not affected by CPPU. The licensee postulated pipe break locations for ASME Section III Class 1, 2 and 3 piping inside and outside containment in accordance with the design stress and fatigue requirements of the plant code of record, ASME *Boiler and Pressure Vessel* (B&PV) Code -Section III, Division 1, 1977 Edition through summer 1979 Addenda for Class 1 piping and ASME B&PV Code - Section III, Division 1, 1974 Edition, through winter 1974 Addenda for Class 2 and 3 piping. The licensee indicated that no new postulated pipe break locations were identified due to CPPU conditions.

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[57] ADAMS Accession No. ML033640024

[58] Attachment 4 to PSEG Letter (LR-N06-0286) to NRC dated September 18, 2006, "Request for License Amendment Extended Power Uprate, Hope Creek Generating Station Facility, Operating License NPF-57, Docket No. 50-354" ADAMS Accession No. ML062680451

[59] General Electric (GE) Licensing Topical Report (LTR) NEDC-33004P-A, "Constant Pressure Power Uprate," Revision 4, Class III July 2003 ADAMS Accession No. ML032170343

Steam Line High Energy Line Breaks (HELB)

The licensee evaluated steam line HELB in the Main Steam (MS), High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) systems at CPPU conditions and presented the results in PUSAR Table 10-1. The tabulated results show no percent increase in mass release, pressure and temperature at postulated break locations. This shows that CPPU has no effect on the steam pressure or enthalpy at the postulated break locations because steam conditions at the postulated break locations are unchanged. Therefore, the staff concurs with the licensee's conclusion that CPPU has no effect on the mass and energy releases from a steam HELB in the MS, HPCI and RCIC systems.

Liquid Line HELB

The licensee notes that increased MS and FW flows may lead to increased break flow rates for liquid line breaks, and re-evaluated the HELB mass and energy releases for the reactor water clean up (RWCU) and FW systems for CPPU. For RWCU, the licensee evaluated the effects of increased mass/energy release on reactor building (RB) pressure, temperature and relative humidity profiles at CPPU conditions. The licensee determined RB subcompartment pressures and temperatures post RWCU line break at each break location at CPPU conditions and submitted tabulated results in response to staff RAI. The tabulated results at UPU flow conditions are enveloped by the current licensing basis pressure and temperature values. The licensee also re-analyzed the mass and energy releases for the FW line breaks at CPPU conditions and concluded that the energy release from the FW line break at CPPU conditions is bounded by the energy release from a MS line break at current licensed conditions.

In the PUSAR, the licensee identified that review of the postulated pipe break criteria determined that for the FW piping at three locations, the cumulative fatigue usage exceeds the postulated pipe break criteria limit. The licensee stated that the existing calculations for these locations will be reviewed to reconcile the cumulative fatigue usage prior to implementation of the CPPU. The licensee's response to an RAI by the NRC staff, the licensee in its response (documented in LR-N07-0099[60] of LCR H05-01, Rev. 1) replied that the initial conclusions in PUSAR are based on a conservative GE screening analysis. The GE screening analysis reported that three locations may have a cumulative usage factor (CUF) greater than 0.1 at CPPU conditions, exceeding HCGS pipe break design criteria. Specifically, two of the three locations referenced in PUSAR Section 3.5.1 are at FW Containment Penetration Nozzles and the third location corresponds to FW Loop A data point 45 in the HCGS FW piping model. The licensee stated in its RAI response that PSEG subsequently re-evaluated the two FW Containment Penetration Nozzles in question at CPPU conditions and re-analyzed the FW piping Loop A model containing data point 45. For the two Containment Penetration Nozzles, the analyzed value of CUF at CPPU conditions is less than the CUF calculated on the basis of original loads and is bounded by the analysis of the original loads. At FW Loop A data point 45, the FW piping reanalysis at CPPU conditions shows CUF less than 0.1. Therefore, the licensee noted that these three locations of FW meet code requirements and HCGS pipe break design criteria at CPPU conditions without any structural modification. In addition, the licensee in response to staff RAI provided a stress and CUF summary for FW inside containment at CPPU conditions. In all instances where Equation 10 exceeds 2.4 Sm, equations 12 and 13 are less than 2.4 Sm. At all locations where the cumulative usage factor exceeds 0.1, a pipe break has already been postulated. Therefore, based upon the reanalysis of the feedwater piping inside

[60] ADAMS Accession No. ML071290559

containment for EPU conditions, no new pipe break locations need to be postulated. The licensee also stated that the evaluations were performed in accordance with the HCGS code of record for Class 1 components, ASME B&PV Code, Div. 1, Section III, 1977 Edition through summer 1979 Addenda. Therefore, based on review of the licensee's response to staff RAI, the NRC staff finds the licensee's response acceptable as the licensee's analysis was performed in accordance with the code of plant record and met plant design criteria.

Based on the above, the staff finds that the licensee has adequately addressed the impact of HELB mass and energy releases for the RWCU and FW systems and concurs with the licensee that at CPPU conditions there is no adverse impact due to these postulated breaks and CPPU conditions do not result in new HELB locations.

Pipe Whip and Jet Impingement

Pipe whip and jet impingement loads resulting from high energy pipe breaks are directly proportional to system pressure. The staff concurs with the licensee that there is no change on existing pipe whip or jet impingement loads on HELB targets or pipe whip restraints because pressure at CPPU conditions is bounded by the original analysis basis pressure. In addition, the licensee has shown that CPPU conditions do not result in new HELB locations (see above).

Design Basis Accident Loss of Coolant Accident (DBA-LOCA)

The Design Basis Accident Loss-of-Coolant Accident (DBA-LOCA) dynamic loads, including the pool swell loads, vent thrust loads, condensation oscillation (CO) loads and chugging loads were originally defined and evaluated for Hope Creek. The evaluation of the structures attached to the torus shell, such as piping system, vent penetrations, and valves are based on these DBA-LOCA hydrodynamic loads. For CPPU conditions, the Licensee re-evaluated these DBA-LOCA torus shell response loads which were found acceptable with no resulting effects on the torus shell attached structures. The licensee also evaluated the SRV loads for CPPU and concluded that the parameters that affect the SRV loads remain unchanged for CPPU. For the first SRV actuations following an event involving RPV pressurization, the only parameter change potentially introduced by CPPU which can affect the SRV loads is an increase in SRV opening setpoint pressure. However, the HCGS CPPU does not include an increase in the SRV opening setpoint pressures. Therefore, dynamic piping loads for SRV lines at CPPU conditions are bounded by those used in the existing analyses.

On the basis of the NRC staff's review, the NRC staff finds the licensee's evaluation of the break locations and associated dynamic effects of the LOCA and SRV loads for CPPU acceptable based on the acceptance criteria documented in GDC-4 and SRP 3.6.2.

<u>Conclusion</u>

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

2.2.2 Pressure-Retaining Components and Component Supports

Regulatory Evaluation

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

Technical Evaluation

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 the licensee evaluated for CPPU include the reactor recirculation (RRS) system, control rod drive (CRD) system, RHR low pressure coolant injection (LPCI) lines, core spray injection lines, SLCS injection line, RPV bottom head drain line, (MS) piping, FW piping, the RCPB portion of the RPV vent line, SRV discharge piping, MSIV drain piping and RWCU piping. The licensee's evaluation additionally 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 CPPU.

The licensee evaluated the above RCPB piping systems in accordance with the methodology documented in NEDC-33004P-A,[61] which maintains the current plant maximum normal operating reactor dome pressure for CPPU. The licensee evaluated ASME Section III Class 1, 2 and 3 piping in accordance with the design stress and fatigue requirements of the plant code of record, ASME B& PV Code -Section III, Division 1, 1977 Edition through summer 1979 Addenda for Class 1 piping and ASME B&PV Code - Section III, Division 1, 1974 Edition,

[61] General Electric (GE) Licensing Topical Report (LTR) NEDC-33004P-A, "Constant Pressure Power Uprate," Revision 4, Class III July 2003 ADAMS Accession No. ML032170343

through winter 1974 Addenda for Class 2 and 3 piping. Pipe stress increases are scaled in proportion to pressure, temperature, and flow increases for CPPU. The licensee's piping evaluation methodology is described in section 5.5.2 and NEDC-32424P-A.[62] Therefore, the NRC staff finds the licensee's methodology acceptable.

The licensee notes that pressures, temperatures, flows and mechanical loads for many of the RCPB piping systems do not increase for CPPU. Seismic, hydrodynamic, SRV discharge inertia loads are not affected by CPPU.

The licensee's evaluation of the RRS system, CRD system, RHR LPCI lines, CS injection lines, SLCS injection line, and RPV bottom head drain line is documented in the proprietary portion of Section 3.5.1 of PUSAR. These systems are shown as not affected by CPPU and are generically dispositioned. The NRC staff reviewed the licensee's evaluation of these RCPB piping systems for CPPU and found it acceptable.

The licensee's review of the RRS system, CRD system, RHR LPCI lines, CS injection lines, SLCS injection line, and RPV bottom head drain line is documented in the proprietary portion of Section 3.5.1 of PUSAR. The NRC staff finds the licensee's review of these RCPB piping systems for CPPU to be acceptable.

The licensee notes that the MS and FW systems exhibit increases in flow of about 16.4 percent for 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 CPPU.

The licensee notes that increased MS flow for CPPU results in increased loads in the MS piping system due to the turbine stop valve (TSV) closure transient. The TSV closure loads bound the MSIV closure loads because the TSVs 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 due to CPPU. No new postulated break locations were identified. In response to NRC staff RAI, the licensee submitted tabulated maximum stress summary results and CUFs and tabulated pipe support evaluations for the main steam inside containment. Review of the tabulated pipe stresses evaluated at CPPU conditions shows that stresses and CUFs are within code of record allowables. Pipe stresses and CUFs at CPPU conditions are also shown to satisfy design basis pipe brake criteria. Main steam pipe support loads inside containment at CPPU conditions are shown to be less than pipe support design loads. 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 at CPPU conditions 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 and no new postulated break locations were identified (see Section 2.2.1 for resolution of the three probable FW new break locations mentioned in PUSAR). In Response to NRC staff RAI, the licensee submitted tabulated maximum stress summary and CUFs results at CPPU conditions for the feed water inside containment. Review of the tabulated pipe stresses evaluated at CPPU conditions shows that stresses and CUFs are

[62] GE Nuclear Energy, Topical Report, NEDC-32424P-A, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," February 1999 (Proprietary). ADAMS Accession No. ML003680231

within code of record allowables. Pipe stresses and CUFs at CPPU conditions are also shown to satisfy design basis pipe brake criteria. The licensee, in its response, also stated that the FW pipe support calculations have been updated and shown to meet all code requirements for the CPPU conditions.

In Section 3.4.1 of the PUSAR, the licensee notes that the MS and FW piping have increased flow rates and flow velocities in order to accommodate CPPU. As a result, the MS and FW piping experience increased vibration levels, approximately proportional to the square of the flow velocities. "Flow Induced Vibration Piping," [63] provides additional information on the plant system piping and components, including MS and FW piping and components that might be subject to increased FIV due to CPPU. The vibration acceptance criteria for the licensee's power ascension program for CPPU are documented in ASME O/M-S/G Part 3, "Requirements for Preoperational and Initial Start-Up Vibration Testing of Nuclear Power Plant Piping Systems." The licensee evaluated the FIV levels associated with the MS and FW piping systems that are projected to increase for CPPU. The staff's reviews of the licensee's FIV and power ascension and testing programs for CPPU are documented in Sections 2.2.6 and 2.12 of this SE.

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

Balance-of-Plant Piping, Components, and Supports

The Balance-of-Plant (BOP) piping systems evaluation consists of a number of piping subsystems that move fluid through systems outside the RCPB piping. The licensee evaluated large and small bore BOP piping and related components, connections and supports similarly to the evaluation of the RCPB piping and supports. The licensee indicated that the original Code of record (as referenced in the pertinent calculations), Code allowables, and analytical techniques were used and no new assumptions were introduced. The BOP systems evaluated by the licensee for the CPPU conditions include the MS (outside containment) including turbine bypass piping, MSIV drain lines, main steam relief valve discharge lines, extraction steam (ES), heater vents and drains, FW and condensate, RWCU (outside containment), RHR (outside containment), CS (outside containment), HPCI (outside containment), RCIC (outside containment), SLC (outside containment), reactor auxiliaries cooling system (RACS), safety auxiliaries cooling system (SACS), turbine auxiliaries cooling system (TACS), fuel pool cooling (FPC) and clean-up, SRV quenchers and supports, filtration recirculation and ventilation system (FRVS) (also referred to as standby gas treatment system (SGTS), off gas, CRD and torus attached piping including ECCS suction strainers.

The Design Basis Accident (DBA)-LOCA dynamic loads, including the pool swell loads vent thrust loads, CO loads and chugging loads were originally defined and evaluated for Hope Creek. The evaluation of the structures attached to the torus shell, such as piping system, vent penetrations, and valves are based on these DBA-LOCA hydrodynamic loads. For CPPU conditions, the Licensee re-evaluated these DBA-LOCA torus shell response loads which were found acceptable with no resulting effects on the torus shell attached structures.

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[63] Attachment 8 to PSEG Letter (LR-N06-0286) to NRC dated September 18, 2006, "Request for License Amendment Extended Power Uprate, Hope Creek Generating Station Facility, Operating License NPF-57, Docket No. 50-354" ADAMS Accession No. ML062680451

The licensee's review of the RCIC and HPCI systems (water segments outside the closed isolation valves) is documented in the proprietary portion of Section 3.5.2 of PUSAR. These systems are shown as not affected by CPPU and are generically dispositioned. The NRC staff reviewed the licensee's evaluation of these BOP piping systems for CPPU and found it acceptable.

The licensee notes that all pipe stresses for the BOP evaluated piping systems have been found to meet the appropriate code criteria for the CPPU conditions, based on the design margins between actual stresses and code limits in the original design. All piping is below the code allowables of the plant code of record, ASME B&PV Code - Section III, Division 1, 1977 Edition through summer 1979 Addenda for Class 1 piping and ASME B&PV Code -Section III, Division 1, 1974 Edition, through winter 1974 Addenda for Class 2 and 3 piping.

The licensee reviewed the pipe supports of the systems affected by CPPU loading increases (MS, FW, ES, drains, vent systems) to determine if there is sufficient margin to code acceptance criteria to accommodate the increased loadings. This review showed that there is adequate design margin between the original design stresses and code limits of most of the supports (with the exception of main steam outside of containment -see below) to accommodate the load increase. The original design analyses have sufficient design margin to justify operation at the CPPU conditions.

The licensee notes that the increase in MS flow due to CPPU results in increased forces from the TSV closure transient. The pipe supports and turbine nozzles for the MS piping system outside containment were evaluated for the increased loading and movements associated with the TSV closure transient at CPPU conditions. This review showed that in most cases there is adequate design margin between the original design stresses and code limits of the supports and nozzles to accommodate the load increase. However, the licensee stated that six pipe supports on the main steam system (outside containment) require modification, prior to CPPU implementation, in order to meet original code limits. The licensee, in response to an NRC staff's RAI, stated that these support modifications have been completed. Modifications ranged from weld additions and upgrades to pipe support hardware upgrade replacements. Responding to staff RAI related to BOP MS piping, the licensee also submitted tabulated maximum stress summary results and tabulated pipe support evaluations. Review of tabulated pipe stresses evaluated at CPPU conditions shows that stresses are within code allowables. Pipe support loads at CPPU conditions were either less than pipe support design loads or in a few cases, where the pipe support loads at CPPU conditions exceeded design loads, existing calculations were reviewed in detail by the licensee and assurance was provided that the support stresses were below stress allowables. The NRC staff reviewed the licensee's main steam evaluation inside and outside containment presented in PUSAR and in the licensee's response to staff RAI and finds that the MS with completed pipe support modifications meets design basis requirements. Therefore, the staff concurs with the licensee that the main steam piping and pipe supports are structurally adequate for CPPU conditions.

The licensee indicates that piping load changes due to the increase in MS flow associated with CPPU do not result in pipe stresses exceeding code allowables. Table 3-10 of PUSAR tabulates pipe stress and pipe support load increases for BOP MS including turbine bypass (outside containment), MSIV drain lines, and ES. The maximum pipe stresses increase by 4.7 percent and the maximum pipe support loads increase (when totaled) by 23.9 percent due the TSV closure transient. The licensee notes that the MSIV closure loads are bounded by TSV loads, as the MSIV closure time is significantly longer than the TSV closure time.

The licensee evaluated the FIV levels associated with the MS and FW piping systems that are projected to increase for CPPU. The staff's evaluation of FIV and power ascension and testing programs for CPPU are documented in Sections 2.2.6 of this SE.

The licensee's review of the MS line flow restrictors is documented in the proprietary portion of Section 3.7 of PUSAR. The NRC staff finds the licensee's review of the MS line flow restrictors for CPPU to be acceptable.

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

Reactor Vessel and Supports

The licensee evaluated the effects of CPPU for the RPV structure and support components for the design, normal, upset, emergency and faulted conditions in accordance with the plant's current design basis. In its evaluation, the licensee compared the proposed power uprate conditions (pressure, temperature and flow) against those used in the design basis. The NRC staff finds the methodology used by the licensee consistent with the NRC-approved methodology documented in Appendix I of the GE report entitled: "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate."[64] The licensee's approach to CPPU is documented in the GE report titled: "Constant Pressure Power Uprate,"[65] which maintains the current plant maximum normal operating reactor dome pressure for CPPU. The NRC staff finds the licensee's methodology acceptable.

The summary of the licensee's RPV structural evaluation is documented in the proprietary portion of Section 3.2.2 of PUSAR. The licensee notes that RPV components with no increase in flow, temperature, reactor internal pressure difference (RIPD) or other mechanical loads for CPPU were not specifically evaluated. In addition, using the methodology documented in Appendix I of NEDC-32424P-A, components with CUFs less than 0.5 were also not specifically evaluated. This methodology has been previously approved by the staff and is acceptable. The stress and fatigue evaluation results are contained in Table 3-3 of PUSAR. Table 3-8 of PUSAR contains maximum stresses for critical components of the RPV internals. The staff's evaluation of the structural integrity of the RPV internals is discussed in Section 2.2.3 of this report.

Based on the NRC staff's review of the licensee's evaluation of the RPV structures and support components for 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.

Control Rod Drive Mechanism

The licensee's evaluation of the CRD mechanism for CPPU is documented in the proprietary portion of Sections 2.5.3 and 3.3.2 of PUSAR. The NRC staff reviewed the licensee's

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[64] GE Nuclear Energy, Topical Report, NEDC-32424P-A, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," February 1999 (Proprietary). ADAMS Accession No. ML003680231

[65] GE Licensing Topical Report NEDC-33004P-A, "Constant Pressure Power Uprate," Revision 4, Class III (Proprietary), dated July 2003. ADAMS Accession No. ML032170343

evaluation. The CPPU loads for CRD are all within the CRD design basis. Therefore, the staff concurs with the licensee's conclusion that the structural integrity of the CRD is maintained for CPPU conditions.

Recirculation Pumps and Supports

For EPU operation, the maximum core flow rate remains unchanged. At CPPU conditions, the RRS drive flow increases slightly (3.5 percent) with pressure, temperature and mechanical loads changing insignificantly. The licensee has documented and evaluated these changes in the proprietary portion of Section 3.5.1 and 3.6 of the PUSAR. The RRS system has been generically dispositioned as not affected by CPPU (see previous pages). The NRC staff concurs with the licensee's conclusion that the RRS system piping, valves, pumps and supports remain structurally adequate to operate at EPU conditions.

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

2.2.3 Reactor Pressure Vessel Internals and Core Supports

Regulatory Evaluation

Reactor pressure vessel internals consist of all the structural and mechanical elements inside the reactor vessel, including core support structures (CSSs). The NRC staff reviewed the effects of the proposed EPU on the design input parameters and the design-basis loads and load combinations for the reactor internals for normal operation, upset, emergency, and faulted conditions. These include pressure differences and thermal effects for normal operation, transient pressure loads associated with LOCAs, and the identification of design transient occurrences. The NRC staff's review covered: (1) the analyses of FIV for safety-related and non-safety-related reactor internal components; and (2) the analytical methodologies, assumptions, ASME Code editions, and computer programs used for these analyses. The NRC staff's review also included a comparison of the resulting stresses and CUFs against the corresponding Code-allowable limits. The NRC's acceptance criteria are based on: (1) 10 CFR 50.55a and GDC-1, insofar as they require that SSCs important to safety be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC-2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions; (3) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents;

and (4) GDC-10, insofar as it requires that the reactor core be designed with appropriate margin to assure that specified acceptable fuel design limits (SAFDLs) are not exceeded during any condition of normal operation, including the effects of AOOs. Specific review criteria are contained in SRP Sections 3.9.1, 3.9.2, 3.9.3, and 3.9.5; and other guidance provided in Matrix 2 of RS-001.

Technical Evaluation

The RPV internals consist of the CSS and non-CSS components. The licensee notes that, with the exception of CRD, 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 CPPU (steam dryer is addressed in section 2.2.6 of this SE). The loads considered in the evaluation include deadweight, seismic, RIPDs, annulus pressurization (AP) and jet loads, flow induced and acoustic loads due to Recirculation Suction Line Break Loss-of-Coolant Accident (RSLB LOCA), and thermal loads. For cases where the loads due CPPU conditions are bounded by the existing-design basis loads, no further evaluation is performed. If the loads increase due to the CPPU, then the effect of the load increase is evaluated further and new stresses are determined by scaling up the existing design basis stresses in proportion to the loads. The resulting stresses are compared against the code allowable values. The NRC staff finds the methodology used by the licensee consistent with the NRC-approved methodology in Appendix I of NEDC-32424P-A, and is therefore acceptable.

The summary of the licensee's RPV internals structural evaluation is documented in the proprietary portion of Section 3.3.2 and 3.4.2 of PUSAR. Table 3-8 of PUSAR contains the governing stresses for the RPV internals, which were quantitatively assessed. All stresses are shown to be within design basis allowable limits. The results of the qualitative assessment of the remaining internals are presented in Section 3.3.2 of PUSAR and are shown to be qualified for CPPU conditions. Section 3.4.2 of PUSAR addresses the FIV influence on reactor internal components.

With respect to the effects of FIV on the RPV internal components, the licensee indicated that the steam separators and dryers in the upper elevations of the RPV are the components most affected by the increased steam flow at CPPU conditions. For components other than the steam separators and dryers, analyses were performed to evaluate the effects of FIV on the reactor internals at CPPU conditions. This evaluation used a reactor power of 3952 MWt and 105 percent of rated core flow. This assessment was based on vibration data obtained during startup testing of the prototype plant (Browns Ferry Unit 1). For components requiring an evaluation but not instrumented in the prototype plant, vibration data acquired during the startup testing from similar plants or acquired outside the RPV was used. The expected vibration levels for CPPU were then estimated by extrapolating the vibration data recorded in the prototype plant or similar plants and on GE Nuclear Energy BWR operating experience. These expected vibration levels were then compared with the established vibration acceptance limits. The peak stresses at critical locations were calculated based on the extrapolated vibration displacements (at sensor locations) and found to be within the GE design criteria acceptance peak stress limit of 10,000 pounds per square inch (psi). Peak stress intensity values less than 10,000 psi are within the endurance limit under which sustained operation is allowed without incurring any cumulative fatigue usage. The licensee concluded that vibration levels of all safety-related reactor internal components are within the acceptance criteria. The licensee noted that peak stress limit of 10,000 psi is conservative in comparison to the ASME Code peak stress limit of

13,600 psi (for austenitic steels). The licensee's vibration evaluation methodology is described in Section 3.4.2 of PUSAR. The NRC staff considers the licensee's methodology to be acceptable.

Based on above review, the NRC staff's concurs with the licensee's conclusion that the RPV internals will continue to maintain their structural integrity for CPPU conditions. The steam dryer assembly is addressed separately in Section 2.2.6 of this SE.

Conclusion

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

2.2.4 Safety-Related Valves and Pumps

Regulatory Evaluation

The NRC staff's review of the EPU license amendment request for Hope Creek included certain safety-related pumps and valves typically designated as Class 1, 2, or 3 under Section III of the ASME B&PV Code and within the scope of Section XI of the ASME Code and the ASME *Code for Operation and Maintenance of Nuclear Power Plants* (OM Code), as applicable. The NRC staff's review focused on the effects of the proposed 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," GL 96-05, "Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves," and GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Valves." The staff also evaluated the licensee's consideration of lessons learned from the motor-operated valve (MOV) program and the application of those lessons learned to other safety-related power-operated valves. The acceptance criteria for the NRC staff review are based on the regulations in 10 CFR Part 50, including: (1) GDC-1 of Appendix A to 10 CFR Part 50, insofar as it requires that structures, systems and components 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, GDC-40, GDC-43, and GDC-46 of Appendix A to 10 CFR Part 50, insofar as they require that the ECCS, the containment heat removal system, the containment atmospheric cleanup systems, and the cooling water system, respectively, be designed to permit appropriate periodic testing to ensure the leak-tight integrity and performance of their active components; (3) GDC-54 of Appendix A to 10 CFR Part 50, insofar as it requires that piping systems penetrating containment be designed with the capability to periodically test the operability of the isolation valves to determine if valve leakage is within acceptable limits; and (4) 10 CFR 50.55a(f), insofar as it requires that pumps and valves subject to that section must meet the in-service testing (IST) program requirements identified in that section. Specific review criteria are contained in SRP Sections 3.9.3 and 3.9.6; and other guidance provided in Matrix 2 of Power Uprate Review Standard RS-001.[66]

Technical Evaluation

The NRC staff asked the licensee to discuss the plans to implement the IST Program incorporates appropriate changes in light of applicable Hope Creek EPU operating conditions. In particular, the licensee was requested to discuss, with examples, its evaluation of the impact of Hope Creek EPU operating conditions on the performance of safety-related pumps, power-operated valves, check valves, safety or relief valves, including consideration of changes in ambient conditions and power supplies (as applicable), and dynamic restraints; and to indicate any resulting component or support modifications, or adjustments to the IST Program, resulting from that evaluation. In its letter dated March 30, 2007,[67] the licensee reported that there are no increases in the required flow rates for any safety-related systems from the planned EPU at Hope Creek. For the postulated DBA LOCA, peak drywell pressure will increase from 48.1 to 50.6 psig, which will affect the test pressure for local leakage testing of containment isolation valves in the IST Program, and also needs to be considered in defining the maximum allowable stroke time for inside-containment MSIVs. Safety-related electrical loads are not changed, and thus there are no IST Program changes associated with Hope Creek EPU power supply changes. With respect to dynamic restraints, the licensee modified six MS pipe supports to accommodate the increased TSV closure transient loads due to higher MS flows.

In its letter dated March 30, 2007, the licensee provided examples of its evaluation of IST Program components for Hope Creek EPU operating conditions. With respect to safety-related pumps, the licensee did not identify any changes. With respect to power-operated valves, the licensee noted that the inboard MSIVs are vented to the drywell atmosphere during the closure stroke. The effect of drywell pressure under accident conditions is considered in determining the maximum allowable stroke time. For other power-operated valves in the IST Program, the only change in inservice testing is to increase the local leak rate test conditions due to the increase in drywell pressure. With respect to check valves, the only impact on these valves is the effect on inservice testing by the increased drywell pressure that defines local leak rate test conditions. With respect to Hope Creek SRVs, CPPU operation will not impact the setpoints or tolerances for over pressure protection or the Automatic Depressurization System (ADS).

In NRC Inspection Report (IR) 50-354/96-04 (dated June 7, 1996), the staff provided the results of inspections to evaluate the licensee's program to verify the design-basis capability of safety-related MOVs in response to GL 89-10 at Hope Creek. The staff closed the review of the GL 89-10 program at Hope Creek in IR 96-04 based on the verification of the design-basis capability of safety-related MOVs. From the review of licensee submittals in response to GL 96-05, the staff prepared an SE dated December 7, 1999, that found that the licensee had established an acceptable program to periodically verify the design-basis capability of safety-related MOVs at Hope Creek. Section 4.1.4, "GL 89-10 Program," of the PUSAR[68] states that process parameters of temperature, pressure, and flow for MOVs within the scope of GL 89-10 were reviewed; and minor changes were identified as a result of Hope Creek EPU operating

[66] ADAMS Accession No. ML033640024
[67] ADAMS Accession No. ML071010243
[68] Attachment 4 to PSEG Letter (LR-N06-0286) to NRC dated September 18, 2006, "Request for License Amendment Extended Power Uprate, Hope Creek Generating Station Facility, Operating License NPF-57, Docket No. 50-354" ADAMS Accession No. ML062680451

conditions. None of the changes were expected to affect component or system operability. The licensee stated that MOV calculations would be revised as necessary.

The staff requested 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 Hope Creek for the potential impact from CPPU operation, including the impact of increased process flows on operating requirements and increased ambient temperature on motor output. In response to the NRC staff's RAI, the licensee reported, in its letter dated March 30, 2007,[69] that the flow rate increase for four systems with MOVs in the GL 89-10 program: MS system, RRS, FW system, and Safety and Turbine Auxiliary Cooling. There was no significant impact on the MOVs (e.g., fluid momentum impact less than 1 percent for butterfly valves) in the GL 89-10 and GL 96-05 program due to the increased flow rates. With respect to motor output, the increase in drywell and torus temperature are bounded by design temperatures, and the increase in ambient temperature of a few degrees Fahrenheit (^{O}F) will not have a significant impact on MOV motor torque output capability.

In Section 4.1.4 of the PUSAR the licensee states that the effect of the Hope Creek EPU on the potential for pressure locking and thermal binding under GL 95-07 was reviewed. Although CPPU operation will increase post-accident drywell and torus temperatures, the Hope Creek EPU operating conditions are bounded by design temperatures. In an RAI, the NRC staff requested that the licensee discuss, with examples, its evaluation of safety-related power-operated gate valves in light of any changes in ambient temperature on the potential for pressure locking or thermal binding resulting from CPPU operation at Hope Creek. In the licensee response letter dated March 30, 2007, the licensee stated that 10 MOVs had been modified as a result of the GL 95-07 review to remove their susceptibility to pressure locking. No other valves were found to have a pressure locking concern. The licensee also evaluated the valves for thermal binding and did not identify any impact from EPU operating conditions.

In Section 4.1.4 of the PUSAR the licensee states that the process parameters of temperature, pressure, and flow for air-operated valves (AOVs) were reviewed, and no changes to the functional requirements of any AOVs were identified. In an RAI, the NRC staff requested that the licensee discuss, with examples, its evaluation of safety-related AOVs for potential impact from CPPU operation at Hope Creek. In the licensee response letter dated March 30, 2007, the licensee summarized the analysis of the Hope Creek EPU project for impact to AOVs. For example, the 4 inboard and 4 outboard MSIVs were analyzed for the effect of Hope Creek EPU operating conditions. The MSIVs continue to have the structural capability to meet pressure boundary requirements. The increased Hope Creek EPU flow rate assists in MSIV closure, but the valve stroke-time remains within allowable limits.

Conclusion

The NRC staff has reviewed the licensee's assessments related to the functional performance of safety-related valves and pumps for Hope Creek in support of the EPU license amendment request. The NRC staff concludes that the licensee has adequately addressed the effects of the proposed Hope Creek EPU on safety-related pumps and valves. The NRC staff further concludes that the licensee has adequately evaluated the effects of the proposed Hope Creek EPU on its valve programs related to GL 89-10, GL 96-05, and GL 95-07; and the lessons learned from those programs to other safety-related power-operated valves. Based on its

[69] ADAMS Accession No. ML071010243

review, the NRC staff concludes that the licensee has demonstrated that safety-related valves and pumps will continue to meet the requirements of GDC-1, GDC-37, GDC-40, GDC-43, GDC-46, GDC-54, and 10 CFR 50.55a(f) following implementation of the proposed Hope Creek EPU. Therefore, the NRC staff finds the proposed EPU acceptable for Hope Creek 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. Equipment associated with systems essential to preventing significant releases of radioactive materials to the environment are also covered by this section. The NRC staff's review focused on the effects of the proposed EPU on the qualification of the equipment to withstand seismic events and the dynamic effects associated pipe-whip and jet impingement forces. The primary input motions due to the safe shutdown earthquake (SSE) are not affected by an EPU. The NRC's acceptance criteria are based on: (1) GDC-1, insofar as it requires that SSCs important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC-30, insofar as it requires that components that are part of the RCPB be designed, fabricated, erected, and tested to the highest quality standards practical; (3) GDC-2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions; (4) 10 CFR Part 100, Appendix A, which sets forth the principal seismic and geologic considerations for the evaluation of the suitability of plant design bases established in consideration of the seismic and geologic characteristics of the plant site; (5) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (6) GDC-14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture; and (7) 10 CFR Part 50, Appendix B, which sets quality assurance requirements for safety-related equipment. Specific review criteria are contained in SRP Section 3.10.

Technical Evaluation

The licensee evaluated safety-related SSCs subject to CPPU conditions. The primary input motions due to the SSE are not affected by a CPPU. The licensee has considered DBA-LOCA conditions, MSLB and other HELBs that could affect safety related mechanical and electrical equipment and components.

The licensee evaluation for the qualification of safety-related electrical equipment subject to DBA-LOCA conditions, MSLB and other HELBs is documented in PUSAR section 10.3.1. The licensee noted that temperature, pressure, and humidity conditions will slightly increase in some areas containing safety-related electrical equipment as a result of CPPU conditions. However, the licensee concluded that the design limits used for the environmental qualification (EQ) evaluations of safety-related electrical equipment bound the increased CPPU levels. Therefore, the staff concurs that safety-related electrical equipment remains qualified for CPPU conditions.

The licensee also evaluated safety-related mechanical equipment subject to increased fluid induced loads, nozzle loads and component support loads due to increased temperatures, flows or pressures for CPPU. The staff concurs with the licensee's conclusion that the mechanical components and component supports are adequately designed for CPPU conditions. The licensee also noted that reevaluation of the safety related mechanical equipment with non-metallic components identified some equipment potentially affected by the CPPU conditions. The qualification of this equipment (resilient seat check valves and LISEGA Type Hydraulic Snubbers) was resolved by reanalysis.

The licensee notes that seismic, hydrodynamic, and SRV discharge inertia loads are not affected by CPPU. The licensee also notes that CPPU does not result in new HELB locations or affect existing HELB evaluations of pipe whip restraints and jet targets (see Section 2.2.1). However, the licensee identified in PUSAR that review of the postulated pipe break criteria determined that for the FW piping at three locations, the cumulative fatigue usage exceeds the postulated pipe break criteria limit. The licensee stated in PUSAR that the existing calculations for these locations will be reviewed to reconcile the cumulative fatigue usage prior to implementation of the CPPU. The licensee's response[70] to an RAI by the NRC staff replied that the initial conclusions in PUSAR are based on a conservative GE screening analysis. The GE screening analysis reported that three locations may have a cumulative usage factor (CUF) greater than 0.1 at CPPU conditions, exceeding HCGS pipe break design criteria. Specifically, two of the three locations referenced in PUSAR Section 3.5.1 are at FW Containment Penetration Nozzles and the third location corresponds to FW Loop A data point 45 in the HCGS FW piping model. The licensee stated, in its RAI response, that PSEG subsequently re-evaluated the two FW Containment Penetration Nozzles in question at CPPU conditions and re-analyzed the FW piping Loop A model containing data point 45. For the two Containment Penetration Nozzles, the analyzed value of CUF at CPPU conditions is less than the CUF calculated on the basis of original loads and is bounded by the analysis of the original loads. At FW Loop A data point 45, the FW piping reanalysis at CPPU conditions shows CUF less than 0.1. Therefore, the licensee noted that these three locations of FW meet code requirements and HCGS pipe break design criteria at CPPU conditions without any structural modification. In addition, the licensee in response to staff RAI provided a stress and CUF summary for FW inside containment at CPPU conditions. In all instances where Equation 10 exceeds 2.4 Sm, equations 12 and 13 are less than 2.4 Sm. At all locations where the cumulative usage factor exceeds 0.1, a pipe break has already been postulated. Therefore, based upon the reanalysis of the feedwater piping inside containment for EPU conditions, no new pipe break locations need to be postulated. The licensee also stated that the evaluations were performed in accordance with the HCGS code of record for Class 1 components, ASME B&PV Code, Div. 1, Section III, 1977 Edition through summer 1979 Addenda. Therefore, based on review of the licensee's response to staff RAI, the NRC staff finds the licensee's response acceptable as the licensee's analysis was performed in accordance with the code of plant record and met plant design criteria.

Based on the foregoing review, the NRC staff concludes that the original seismic and dynamic qualification of safety-related mechanical and electrical equipment for HCGS is not affected by CPPU.

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[70] PSEG Letter (LR-N07-0099) to NRC dated April 30, 2007, "Response to Request for Additional Information, Request for License Amendment – Extended Power Uprate." ADAMS Accession No. ML071290559

Conclusion

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

2.2.6 Additional Review Areas (Mechanical and Civil Engineering) – Including Steam Dryer

See Appendix A for Steam Dryer Information

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 their safety functions under significant environmental stresses which could result from a DBA. The NRC staff's review focused on the effects of the proposed power uprate on the environmental conditions to which the mechanical and electrical equipment will be exposed during normal operation, AOOs, and accidents. The staff's review was conducted to ensure that the equipment will continue to be capable of performing their 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 set forth in 10 CFR Part 50. Specific review criteria are contained in SRP Section 3.11 and other guidance provided in Matrix 2 of Power Uprate Review Standard RS-001.[71]

Technical Evaluation

Appendices A and B of 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. EQ 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., mechanical seals, gaskets, lubricants, fluids for hydraulic systems, and diaphragms). Mechanical equipment experiences the same environmental conditions as those defined in 10 CFR 50.49 for electrical equipment.
In other sections of this SE, the NRC staff describes its evaluation of the capability of electrical equipment to continue to perform their safety functions under EPU operating conditions. In that

[71] ADAMS Accession No. ML033640024

section, the NRC staff found that the licensee had adequately addressed the effects of the proposed power uprate on the EQ of electrical equipment at Hope Creek. The staff finds that the conditions used by the licensee in reviewing the EQ of electrical equipment are sufficient for mechanical equipment in support of the proposed Hope Creek EPU.

Section 10.3, "Environmental Qualification," of the PUSAR[72] indicates that safety-related components are required to be qualified for the environment in which they are intended to operate. In Section 10.3.2, "Mechanical Equipment with Non-Metallic Components," of the PUSAR, the licensee states that the re-evaluation of safety-related mechanical equipment with non-metallic components identify some equipment potentially affected by EPU operating conditions that were resolved by re-analysis. In response to an NRC staff RAI, the licensee, in its letter dated March 30, 2007,[73] described the Hope Creek, Mechanical Equipment Qualification (MEQ) Program, that established the capability of active safety-related mechanical equipment to perform its required safety function for the life of the plant including postulated accident conditions. Non-metallic components used in mechanical equipment (such as pumps, fans, and check valves) include gaskets, diaphragms, seals, lubricating oil or grease, fluids for hydraulic systems, flexible hoses, and packing. The licensee analyzed these components to ensure that the material can perform its intended function during postulated normal and accident conditions (e.g., temperature and radiation). The licensee determined that the current temperature and pressure profiles bounded the postulated DBA conditions due to the proposed Hope Creek EPU. Radiation conditions, however were determined by the licensee, not to be bounded by current analysis. From review of equipment in the MEQ Program, the licensee determined that the postulated dose damage due to the EPU is higher than the radiation damage threshold of the non-metallic parts of the resilient seated check valves (i.e., MSIV accumulator check valves) and Hydraulic Snubbers. Specific analyses performed for this equipment determined that the calculated doses remain below the radiation damage threshold. These check valves and snubbers are addressed by the surveillance requirements (SRs) of the Hope Creek TSs.

In Section 10.3.3, "Mechanical Component Design Qualification," of the PUSAR, the licensee states that mechanical design of equipment/components in certain systems is affected by operation at EPU conditions due to slightly increased temperatures and, in some cases, flow. The licensee states that the revised operating conditions do not significantly affect the cumulative usage fatigue factors of mechanical components. The licensee states that the increased fluid induced loads on safety-related components and supports are insignificant. In an RAI, the NRC staff requested the licensee to: (1) discuss the EQ methods and approaches applied to mechanical equipment (including pumps, power-operated valves, safety-relief valves, and check valves) and their supports; (2) provide examples of the increased temperatures, flows, and loads resulting from Hope Creek EPU operating conditions to demonstrate that the impact is insignificant; and (3) describe the surveillance and maintenance program for mechanical equipment to ensure functionality during their design life. In response by letter dated March 30, 2007, the licensee described the evaluation of the impact of DBA and normal operating conditions to establish the EQ of mechanical equipment under EPU operating conditions. The capability of non-metallic material to withstand temperature and radiation was established using material data available in the industry to ensure that the mechanical equipment can perform their intended function under postulated environmental conditions during

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[72] Attachment 4 to PSEG Letter (LR-N06-0286) to NRC dated September 18, 2006, "Request for License Amendment Extended Power Uprate, Hope Creek Generating Station Facility, Operating License NPF-57, Docket No. 50-354" ADAMS Accession No. ML062680451

[73] ADAMS Accession No. ML071010243

normal and accident conditions during their design life. Among the key parameters during accident conditions used to evaluate post-Hope Creek EPU impact on equipment in the MEQ Program are LOCA peak temperature and pressure inside the drywell, EQ radiation dose, and HELB peak temperature and pressure outside primary containment. Examples of mechanical equipment that were evaluated for increased temperature, flow, and load resulting from Hope Creek EPU operating conditions are FW isolation check valves, TSVs, and FW heaters and relief valves. The licensee has programs in place (such as AOV and MOV programs) that use inspection, test, or rebuild activities to provide confidence in the ability of mechanical components to function in accordance with the specified requirements during their design life.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed Hope Creek EPU on the EQ of mechanical equipment at Hope Creek. Based on the above described review, the staff concludes that the licensee has adequately addressed the effects of the proposed Hope Creek EPU on the environmental conditions for the qualification of mechanical equipment. The NRC staff further concludes that the mechanical equipment at Hope Creek will continue to meet the relevant requirements of 10 CFR 50.49 following implementation of the proposed Hope Creek EPU. Therefore, the NRC staff finds the proposed Hope Creek EPU acceptable with respect to the EQ of mechanical equipment at Hope Creek.

2.3 Electrical Engineering

2.3.1 Environmental Qualification of Electrical Equipment

2.3.1.1 Regulatory Evaluation

Nuclear Power plant electrical equipment EQ involves demonstrating that the electrical equipment components are capable of performing the designated safety function under significant environmental stresses which could result from DBAs. The NRC staff's review focused on the effects of the proposed Hope Creek EPU on the environmental conditions that the electrical equipment will be exposed to during normal operation, anticipated operational occurrences (AOOs), and accidents. The NRC staff's review was conducted to ensure that the electrical equipment will continue to be capable of performing its safety functions following implementation of the proposed Hope Creek EPU. The NRC's acceptance criteria for EQ of electrical equipment are based on 10 CFR 50.49, which sets forth requirements for the qualification of electrical equipment important to safety that is located in a harsh environment. Specific review criteria are contained in SRP Section 3.11 and other guidance provided in Matrix 3 of Power Uprate Review Standard RS-001.[74]

Technical Evaluation

Inside Containment

EQ for safety-related electrical equipment located inside containment is based on main steam line break (MSLB), DBA, and LOCA conditions and their resultant temperature, pressure, humidity, and radiation consequences. EQ also includes the environment expected to exist during normal plant operation. The licensee stated that normal temperatures are expected to increase slightly but continues to be bounded by the normal temperatures used in the EQ analyses. Furthermore, the licensee stated that post-accident peak temperature and pressure increase slightly but remain bounded by the peak temperature and pressure conditions used in the EQ analyses.

The licensee stated that radiation EQ for safety-related electrical equipment inside containment is based on the radiation environment expected to exist during normal operations, post-LOCA conditions, and the resultant cumulative radiation doses. The accident radiation levels increase by < 20 percent due to the Hope Creek EPU. The total integrated radiation doses (normal plus accident) for Hope Creek EPU operating conditions were determined not to adversely affect qualifications of equipment inside containment. The peak accident temperature and pressure increase is due to the EPU but remains bounded by the accident profile assumed for EQ. However, the increased radiation doses resulted in a reduction of radiation life of Target Rock Solenoid Valves (TRSV) located inside containment. In its March 13, 2007, supplemental letter,[75] the licensee described the methodology used to evaluate the radiation life of the TRSVs. The TRSVs are only needed to depressurize the reactor vessel during a small break LOCA or a non-LOCA LOOP. The methodology used actual separation distances and a conservative non-LOCA post-accident source term to determine that the expected radiation life of the TSRVs extend up to the design life of the plant. The licensee concluded that the qualified life of EQ components inside containment is adequate for the remaining life of the plant. The

[74] ADAMS Accession No. ML033640024
[75] ADAMS Accession No. ML070790508

staff reviewed the LAR, RAI responses and FSAR; based on this information, the staff finds that the current EQ parameters remain bounding for the EPU.

Outside Containment

The licensee stated that accident temperature, pressure, and humidity environments used for qualification of equipment located in harsh environments outside containment result from MSLB or other HELBs, whichever is limiting for each plant area. The HELB temperature and pressure profiles are bounded by existing values used for equipment qualification, as indicated in Table 10-2 of NEDC-33076P. The accident temperatures outside containment resulting from a LOCA/MSLB inside containment remain unchanged. The normal temperature, pressure, and humidity conditions slightly increased in some areas containing EQ equipment, but are bounded by the design limits used for EQ evaluations.

The post-accident radiation exposure in the RB remains bounding for the EPU condition. The accident radiation levels increase by < 20 percent due to the Hope Creek EPU. The increased radiation doses result in a reduction of the radiation life of BPSs. The BPSs are required to operate for 12 hours during and following a LOCA; therefore, a conservative radiation dose was used for the RB for these 12 hours. The licensee stated that the qualified life of equipment remains bounding due to the compensating margin in the qualified dose except the Barksdale Pressure Switches (BPSs). In its March 13, 2007, supplemental letter,[76] the licensee described the methodology used to evaluate the radiation life of the BPSs. The methodology used actual separation distances and a conservative dose to determine that the expected radiation life of the BPSs extend up to the design life of the plant. The licensee concluded that the qualified life of EQ components outside containment is adequate for the remaining life of the plant.

Conclusion

The NRC staff has reviewed the LAR and RAI responses for the effects of the proposed Hope Creek EPU on the EQ of electrical equipment and concludes that the licensee has adequately addressed the effects of the environmental conditions for qualification of electrical equipment under the proposed EPU operating conditions. The NRC staff further concludes that the electrical equipment will continue to meet the relevant requirements of 10 CFR 50.49 following implementation of the proposed Hope Creek EPU. Therefore, the NRC staff finds the EPU acceptable with respect to the EQ of electrical equipment.

2.3.2 Offsite Power System

Regulatory Evaluation

The offsite power system includes two or more physically independent circuits capable of operating independently of the onsite standby power sources. The 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 NRC staff's 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 Hope Creek EPU. The NRC's acceptance criteria for offsite power systems are based on GDC-17. Specific review criteria are contained in SRP Sections

[76] ADAMS Accession No. ML070790508

8.1 and 8.2, Appendix A to SRP Section 8.2, and Branch Technical Positions (BTPs) Public Service Board (PSB)-1, ICSB-11 and other guidance provided in Matrix 3 of Power Uprate Review Standard RS-001.[77]

Technical Evaluation

Grid Stability

Reliability First Corporation (RFC) is the North American Electric Reliability Corporation (NERC) Regional Reliability Council to improve the reliability of the bulk power system in the Hope Creek power supply region. RFC is the successor organization to the Mid-Atlantic Area Council (MAAC), the East Central Area Coordination Agreement, and the Mid-American Interconnected Network. RFC currently uses legacy MAAC standards.

As the regional transmission organization, the PJM Interconnection is responsible for the operation of the transmission grid. PJM coordinates the planning process for connection of new generation, coordinates the reliability studies for operation of new generation, and oversees the construction of the required interconnection facilities. The licensee stated that the PJM studies are documented in the Hope Creek Artificial Island Operating Guide[78] which demonstrate that: (1) the power system is stable for all three-phase and single-phase faults studied, when cleared by relay protection in accordance with planned settings; (2) under all power-flow conditions tested, the stations and transmission system satisfy the MAAC Reliability Principles and Standards; (3) tripping of Hope Creek will not have detrimental effects on grid stability; and (4) the Artificial Island bus remains stable and available. In its March 13, 2007, supplemental letter,[79] the licensee demonstrated that the PJM study bounds the current grid conditions via the PJM Regional Transmission Expansion Planning Process. Attachment 9 to the licensee letter dated November 7, 2005,[80] provided a summary of the grid impact studies performed by the PJM to evaluate the effect of the EPU operation. The staff reviewed the summary of grid impact studies and concluded that the EPU will not impact grid stability.

In the March 13, 2007, letter, the licensee stated that Hope Creek provided PJM with the minimum required 500 kV switchyard voltage to be maintained to ensure sufficient voltage at Class 1E equipment during anticipated operating conditions and DBAs. Furthermore, the PJM planning process and operating practices for maintaining adequate system voltage, MAAC standards, and existing Hope Creek distribution calculations provide assurance that the tripping of Hope Creek EPU levels will not cause inadequate post-trip voltage.

The licensee made several modifications in order to support EPU. The licensee stated in its March 13, 2007, supplemental letter, that the following modifications were included in the grid impact studies: (1) the addition of a 500kV circuit breaker in the Hope Creek switchyard; (2) main transformer replacement; (3) LP turbine replacement; and (4) HP turbine replacement.

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[77] ADAMS Accession No. ML033640024
[78] PSEG Engineering Evaluation A-5-500-EEE-1686
[79] ADAMS Accession No. ML070790508
[80] ADAMS Accession No. ML053200202

Main Generator

As a result of the EPU, the main generator rating for Hope Creek increased to 1373.1 mega volt-ampere (MVA) at 0.94 power factor (pf) lagging from 1300 MVA at 0.9 pf lagging. To support the EPU, the licensee has upgraded the main generator stator cooling. The licensee stated that the main generator is field current limited at 1265.5 megawatts electric (MWe), resulting in a 0.931 pf lagging. At EPU operating conditions, the reactive limits of the generator are +315/-428 megavolt-ampere reactive (MVAR). The minimum limit of 315 MVAR is required to maintain generator stability. The licensee stated that the existing protective relaying for the main generator is adequate under Hope Creek EPU operating conditions. The staff reviewed the LAR and FSAR and the staff finds that the generator is capable of operation at EPU conditions.

Iso-Phase Bus Duct

The iso-phase bus at Hope Creek operates at 25 kV. The bus is divided into sections with ratings appropriate for each section. The licensee modified the main phase bus duct to have a continuous rating of 34,000 Amperes (A) from a rating of 32,000 A. The delta bus has been modified to have a rating of 19,630A from a rating of 18,500 A. The licensee has accomplished this by modifying the iso-phase bus cooling system to remove bus duct heat under EPU operating conditions.

Main Bank Transformers

The licensee stated that the Main Bank Transformers have been replaced in order to support generation at a higher output. The new three-phase transformer bank is rated at 1400.1 MVA and is adequate to support Hope Creek EPU operating conditions. The licensee stated that the existing protective relaying for the main bank transformers is adequate under Hope Creek EPU operating conditions.

Station Service Transformers

The licensee’s evaluation confirmed that the current ratings of the station service transformers supplying the 4.16 kV Class 1E system are adequate for the Hope Creek EPU and thus, no modifications were required.

Switchyard

A 500kV circuit breaker was installed in the Hope Creek switchyard to provide backup clearing in the event of a stuck breaker. The licensee stated that the grid study demonstrated that the addition of the 500 kV circuit breaker improves system stability since the addition of this breaker eliminates the possibility of a fault on the Hope Creek – Red Lion transmission line coupled with a breaker failure from tripping the Salem – Hope Creek line. Furthermore, the licensee stated that the existing protective relaying for the switchyard remains adequate for Hope Creek EPU operating conditions.

Non-Class 1E Loads

The licensee stated that primary and secondary condensate pumps (CPs) will experience increased flow demand at Hope Creek EPU operating conditions. The electrical load demand associated with the motors for these pumps will increase due to the increase in flow but remain within their nameplate capacity. Additionally, the licensee stated that the Motor Generator set motors' brake horsepower increases by 6.0 percent but remains within its nameplate capacity.

Conclusion

The NRC staff has reviewed the LAR, RAI responses, and FSAR for the effects of the proposed Hope Creek 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 Hope Creek 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 NRC staff further concludes that the impact of the proposed Hope Creek EPU on grid stability is insignificant based on reviewing the LAR, RAI responses and FSAR. Therefore, the NRC staff finds the proposed Hope Creek EPU acceptable with respect to the offsite power system.

2.3.3 AC Onsite Power System

Regulatory Evaluation

The alternating current (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. Specific review criteria are contained in SRP Sections 8.1, 8.3.1 and other guidance provided in Matrix 3 of Power Uprate Review Standard RS-001. [81]

Technical Evaluation

The NRC staff reviewed the licensee's submittal to determine whether the EDGs would remain capable of performing their intended function at Hope Creek EPU operating conditions. The licensee stated that its review of the loads for Hope Creek EPU operation indicated that there is no flow or pressure increase required of any ECCS equipment. Therefore, the amount of power required to perform safety-related functions (pump and valve loads) does not increase under the proposed Hope Creek EPU. The licensee concluded that the Hope Creek EDGs have sufficient capacity to supply all required loads, to achieve and maintain safe shutdown conditions, and to operate the ECCS equipment following postulated accidents and plant transients.

[81] ADAMS Accession No. ML033640024

Conclusion

The NRC staff has reviewed the LAR and FSAR for the effects of the proposed Hope Creek EPU on the ac onsite power system and concludes that the licensee has adequately accounted for the effects of the proposed Hope Creek EPU on the system's functional design. The NRC staff further concludes that the ac onsite power system will continue to meet the requirements of GDC-17 following implementation of the proposed Hope Creek EPU. Therefore, the NRC staff finds the proposed Hope Creek 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. Specific review criteria are contained in SRP Sections 8.1, 8.3.2 and other guidance provided in Matrix 3 of Power Uprate Review Standard RS-001.[82]

Technical Evaluation

The NRC staff reviewed the licensee's submittal to determine whether the dc system and its components would remain capable of performing their intended design function at Hope Creek EPU operating conditions. The licensee stated that operation at Hope Creek EPU conditions would not increase any load beyond nameplate rating or require revision to a component's duty cycle. Therefore, the dc power system remains adequate to supply safety-related systems at Hope Creek EPU levels.

Conclusion

The NRC staff has reviewed the LAR and FSAR for the effects of the proposed Hope Creek EPU on the dc onsite power system and concludes that the licensee has adequately accounted for the effects of the proposed Hope Creek EPU on the system's functional design. The NRC staff further concludes that the dc onsite power system will continue to meet the requirements of GDC-17 following implementation of the proposed Hope Creek EPU. Adequate physical and electrical separation exists and the system has the capacity and capability to supply power to all safety-related loads and other required equipment. Therefore, the NRC staff finds the proposed Hope Creek 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 a LOOP concurrent with

[82] ADAMS Accession No. ML033640024

a turbine trip (TT) 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 (AAC) sources". The NRC staff's review focused on the impact of the proposed Hope Creek 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. Specific review criteria are contained in SRP Sections 8.1 and Appendix B to SRP Section 8.2, and other guidance provided in Matrix 3 of Power Uprate Review Standard RS-001.

Technical Evaluation

The licensee re-evaluated SBO using the guidelines of NUMARC 87-00. The licensee stated that Hope Creek's response to and coping capabilities for an SBO event would be affected slightly by the increase in the initial Hope Creek EPU power level and decay heat. However, the licensee stated that no changes are necessary to the systems and equipment used to respond to an SBO and that SBO coping duration of 4 hours does not change under Hope Creek EPU operating conditions.

The licensee stated that areas containing equipment necessary to cope with an SBO event were evaluated for the effect of loss-of-ventilation due to an SBO. The licensee's evaluation showed that equipment operability is bounded due to conservatism in the existing design and qualification bases. The battery capacity remains adequate to HPCI/RCIC operation at EPU operating conditions. In addition, adequate compressed gas capacity exists to support main steam relief valve actuations. The current condensate tank (CST) inventory reserve (135,000 gallons), for HPCI/RCIC use, ensures that adequate water volume is available to remove decay heat, depressurize the reactor, and maintain reactor vessel level above the top of active fuel (TAF) (109,000 gallons required).

Conclusion

The NRC staff has reviewed the LAR and PUSAR for the effects of the proposed Hope Creek 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 staff concludes that the licensee has adequately evaluated the effects of the proposed Hope Creek EPU on SBO and demonstrated that the plant will continue to meet the requirements of 10 CFR 50.63 following implementation of the proposed Hope Creek EPU. Therefore, the NRC staff finds the proposed Hope Creek EPU acceptable with respect to SBO.

2.4 Instrumentation and Controls

2.4.1 Reactor Protection, Safety Features Actuation, and Control Systems

Regulatory Evaluation

Instrumentation and control systems are provided (1) to control plant processes having a significant impact on plant safety, (2) to initiate the reactivity control system (including control rods), (3) to initiate the engineered safety features (ESF) systems and essential auxiliary supporting systems, and (4) for use to achieve and maintain a safe shutdown condition of the plant. Diverse instrumentation and control systems and equipment are provided for the express purpose of protecting against potential common-mode failures of instrumentation and control protection systems. The NRC staff conducted a review of the reactor trip system, engineered safety feature actuation system (ESFAS), safe shutdown systems, control systems, and diverse instrumentation and control systems for the proposed Hope Creek EPU to ensure that these systems and any changes necessary are adequately designed such that the systems continue to meet their safety functions. The NRC staff's review was also conducted to ensure that failures of the systems do not affect safety functions. The NRC's acceptance criteria related to the quality of design of protection and control systems are based on 10 CFR 50.55a(a)(1), 10 CFR 50.55a(h), and GDC 1, 2, 4, 13, 19, 20, 21, 22, 23, 24, 25, and 29. Specific review criteria are contained in SRP Sections 7.0, 7.2, 7.3, 7.4, 7.7, and 7.8. and other guidance provided in Matrix 4 of Power Uprate Review Standard RS-001.[83]

Technical Evaluation

Suitability of Existing Instruments

For the proposed Hope Creek 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 to be changed, the licensee's evaluations found most of the existing instrumentation acceptable for the proposed power uprate operation. The licensee's evaluation resulted in the following changes at Hope Creek:

Equipment or Function	**Change**
Main Steam Line Flow Transmitter	Replace the existing transmitter to accommodate the EPU calibrated range
Condensate Pre-Filter Flow element	Replace the existing flow element to accommodate the EPU calibrated range

[83] ADAMS Accession No. ML033640024

Stator Water Cooling System	Flow Orifice, Flow Meter, and Winding Inlet Pressure Gauge were replaced to accommodate increase Stator Water pressure and flow required for the increased generator rating
High Pressure Turbine Instrumentation	Replace instrumentation to accommodate the HP Turbine replacement
Main Steam Line Flow Instrumentation	Rescale the instrument to accommodate the input to the NSSS Isolation Logic in psid (Mlbs/hr) for EPU range.
Main Steam Line Flow Instrumentation	Rescale the instrumentation to accommodate the input to the Digital Feedwater Control System for EPU range in psid (Mlbs/hr).
Main Steam Line Flow Recorders, Indicators, Computer points	Rescale the instrumentation to accommodate the EPU range in Mlb/hr
Feedwater Flow Recorder, computer points	Rescale the instrumentation to accommodate the EPU range in Mlb/hr
Condensate pre-filter flow	Rescale the instrumentation to accommodate the EPU range in gpm
Condensate demineralizer flow	Rescale the instrumentation to accommodate the EPU range in gpm
Hydrogen Water Chemistry Injection	Setpoint is revised in terms of FW flow because of increase in total rated FW flow, but remains same in terms of percent rated thermal power
Primary Condensate Pump 75 percent permissive	The setpoint is revised because of the increase in total rated flow and full-scale range.
Secondary Condensate Pump 85 percent permissive	The setpoint is revised because of the increase in total rated flow and full-scale range.
Reactor Core Isolation Cooling turbine exhaust pressure	Change setpoint to ensure system availability for the duration assumed for the SBO event.
Neutron Monitoring	Re-calibrate APRM and RBM to reflect EPU operation

Electrohydraulic Control and Turbine Supervisory Instrumentation	Replace instrumentation.
APRM flow biased trip reference card	Replace this card to accommodate the ARTS/MELLA changes.

The above instrument changes will be made to accommodate the revised process parameters at Hope Creek EPU operating conditions. Since the instrumentation and control functions related to the above changes will be confirmed by the licensee during post-modification testing, power ascension testing, and instrument calibration, as applicable, the NRC staff has reasonable assurance that the instrumentation will continue to perform their intended process and safety functions at Hope Creek EPU operating conditions.

Instrument Setpoint Methodology

The licensee has requested TS changes associated with instrument setpoint or AVs related to APRM flow biased reactor trip, RBM Instrumentation, and MS Line Isolation on High Flow with this amendment request. In Section 5.3, "Technical Specification Instrument Setpoints," of the PUSAR,[84] the licensee states that none of these instruments perform a function related to the protection of a TSs SL. Therefore, the proposed changes to the TSs setpoints do not involve a limiting safety system setting (LSSS) that protects a plant SL.[85] 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 limiting trip setpoint. The AAL which the licensee has defined as desired range/recalibration tolerance is established by taking the square root of the sum of the squares of calibration tolerance and vendor accuracy numbers. The AAF value is established by taking the square root of the sum of the squares of the calibration tolerance, measurement and test equipment uncertainties and drift numbers. The NRC staff finds that the licensee's methodology to calculate these numbers meets the guidance provided in the RIS 2006-17[86] and therefore is acceptable to the staff.

The licensee has further 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 the instrument exceeds the desired range/recalibration tolerance (AAL band) but is below the acceptable value (AAF band), the instrument will be re-calibrated. However, if the instrument is found to be outside the acceptable value (AAF band) it will also be entered in the corrective action program. If the instrument is found outside the AV, then it will be declared inoperable and the action required by

[84] Attachment 4, Page 5-8 of PSEG Letter (LR-N06-0286) to NRC dated September 18, 2006, "Request for License Amendment Extended Power Uprate, Hope Creek Generating Station Facility, Operating License NPF-57, Docket No. 50-354" ADAMS Accession No. ML062680451

[85] Attachment 1, page 22-23 of PSEG Letter (LR-N06-0286) to NRC dated September 18, 2006, "Request for License Amendment Extended Power Uprate, Hope Creek Generating Station Facility, Operating License NPF-57, Docket No. 50-354" ADAMS Accession No. ML062680451

[86] NRC Regulatory Issue Summary, "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." August 24, 2006. ADAMS Accession No. ML051810077

the TS will be taken. The above approach provides an acceptable means to manage instrument setpoints and is consistent with the guidance provided by the RIS 2006-17 and therefore is acceptable to the staff.

Based on the above, the staff concludes that there is reasonable assurance that plant will operate in accordance with the safety analysis and that the operability of the instrumentation is ensured. Therefore, the staff finds the proposed changes meet the requirements of 10 CFR 50.36 and the guidance in RG 1.105, "Setpoints for Safety-Related Instrumentation," Revision 3, December 1999.

Conclusion

The NRC staff has reviewed the licensee's application related to the effects of the proposed Hope Creek EPU on the functional design of the reactor trip system, ESFAS, safe shutdown system, and control systems. The NRC staff concludes that the licensee has adequately addressed the effects of the proposed Hope Creek EPU on these systems and that the changes that are necessary to achieve the proposed Hope Creek EPU are consistent with the plant's design basis. The NRC staff further concludes that the systems will continue to meet the requirements of 10 CFR 50.55a(a)(1), 10 CFR 50.55(a)(h), and GDC-1, 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 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; flooding due to pipe failures is evaluated in Section 2.5.1.3. Because the staff's review focuses on increases of fluid volumes in tanks and vessels that will occur as a result of the power uprate and the licensee indicated in Section 10.1 of the Hope Creek PUSAR that fluid volumes in tanks and vessels will not increase as a result of the CPPU, an evaluation of this particular section by the staff is not required.

2.5.1.1.2 Equipment and Floor Drains

The function of the equipment and floor drainage system (EFDS) is to assure that waste liquids, valve and pump leakoffs, and tank drains are directed to the proper area for processing or disposal. The EFDS consists of the radioactive and nonradioactive waste drainage and collection systems. The radioactive and nonradioactive drainage systems are segregated to prevent the transfer of radioactive contamination to the nonradioactive liquid wastes and uncontrolled access areas. The licensee indicated that sources and volumes of liquids for system drains are not affected by the proposed CPPU (Table 6-5 of the Hope Creek PUSAR), and the licensee also stated in Section 8.1 of the PUSAR and in supplemental letter dated March 22, 2007,[87] that the EDFS backflow at maximum flood levels and infiltration of radioactive water into nonradioactive water drains will not change as a result of the CPPU. 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 due to any increases that may be necessary in fluid volumes and installation of larger capacity CWS pumps or piping. Hope Creek is not installing larger CWS pumps or CWS piping for CPPU operation. Because the impact of the proposed power uprate on the licensee's flooding analysis is considered in Sections 2.5.1.1.1 and 2.5.1.3 of this evaluation, a separate evaluation for the CWS in this section is not required.

[87] ADAMS Accession No. ML070930442

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 high-pressure system ruptures. Potential missile sources include pressurized systems and components, and high-speed rotating machinery. The purpose of the staff's review is to confirm that: (1) SSCs important to safety are protected from internally generated missiles; and (2) the failure of SSCs not important to safety due to missiles will not pose a challenge to SSCs that are important to safety. The 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 staff's 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, "Environmental and Dynamic Effects Design Basis," insofar that SSCs important to safety should be protected from the effects of internally generated missiles, and other licensing basis considerations that are applicable. The staff's review related to internally generated missiles is performed in accordance with the guidance in Section 2.1 of RS-001, Matrix 5. Acceptability for EPU operation is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Sections 3.5.1.1 and 3.5.1.2 of the Hope Creek UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

Technical Evaluation

The licensee evaluated the impact of CPPU on the possibility of generating internally generated missiles that may result from failures in high energy systems and overspeed of rotating equipment in Matrix 5 of Attachment 10 to PSEG letter dated November 7, 2005.[88] The licensee determined that the CPPU does not result in any condition (system pressure increase or equipment overspeed) that could result in an increase in the generation of internally generated missiles. In addition, the licensee determined that the CPPU does not entail any changes in equipment configurations that could change the effect of internally generated missiles on safety-related or non-safety related equipment. Specifically, all CPs and reactor feed pumps remain within their nameplate rating and the existing turbine overspeed setpoint for the reactor FW pumps (RFPs) is not increased for CPPU operation. Replacement of the HP turbine will result in an increase in ES pressure, but the ES lines are within the turbine building and will not impact any SSCs important to safety. Main steam pressure will not increase and thus the system will not be more likely to generate missiles as a result of the CPPU. The reactor feed pressure will increase to accommodate the CPPU, but the increase is not substantial. UFSAR Table 3.5-1 indicates that potential FW generated missiles will be contained in subcompartments, which is not expected to change as a result of this minor increase in FW pressure. With respect to potential missiles that are generated by the main

[88] PSEG Letter (LR-N05-0258) to NRC dated November 7, 2005, "Request for License Amendment Extended Power Uprate." ADAMS Accession No. ML053200202

turbines, the licensee indicated that the high and LP turbines for CPPU operation are of the monoblock design and consistent with the position stated by General Electric,[89] a separate turbine missile analysis is not required.

Based on a review of the information provided, the NRC staff is satisfied 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 CPPU will not cause the effects of internally generated missiles (outside containment) on SSCs important to safety to be more severe than what was previously assumed. The NRC staff also agrees that a separate main turbine missile analysis is not required provided that overspeed of the main turbines during CPPU operation will not exceed the overspeed limit that was previously established. The NRC staff's review of main turbine overspeed considerations is evaluated in Section 2.5.1.2.2 and is not included within the scope of this section. Therefore, given these considerations, the staff agrees that SSCs important to safety will continue to be adequately protected from internally generated missiles following CPPU implementation.

The licensee has not requested NRC review and approval of any changes to the licensing basis related to protection from internally generated missiles for power uprate operation and this evaluation does not constitute NRC approval of any changes to the licensing basis in this regard.

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 to be acceptable with respect to the protection of SSCs important to safety from internally generated missiles.

2.5.1.2.2 Turbine Generator

Regulatory Evaluation

The turbine generator (TG) does not perform a safety function and it is not safety-related. However, the TG is of regulatory significance because the large steam turbines of the TG set have the potential for producing high energy missiles, especially if the turbines exceed their rated speed. The turbine control system, main stop valves, control valves, intercept and intermediate stop valves control the turbine speed and include design features that prevent turbine overspeed conditions. The NRC staff's review of the TG for proposed power uprates focuses on the effects of the proposed EPU on the turbine overspeed protection features to confirm that adequate turbine overspeed protection will be maintained. The criteria that are most applicable to the staff's review of the TG for proposed power uprates are based on GDC 4, "Environmental and Dynamic Effects Design Basis," insofar that SSCs important to safety should be protected from the effects of turbine missiles, and other licensing basis considerations that are applicable. The staff's review related to the TG is performed in accordance with the

[89] General Electric Licensing Topical Report, NEDC-33004P-A, "Constant Pressure Power Uprate," Revision 4, dated July 31, 2003. ADAMS Accession No. ML032170332

guidance provided in Section 2.1 of RS-001, Matrix 5, and acceptability for EPU operation is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Sections 3.5.1.3 and 10.2 of the Hope Creek UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

Technical Evaluation

The licensee's evaluation of the impact that the proposed CPPU will have on the capability to prevent overspeed of the main turbine is provided in Section 7.1 of the Hope Creek PUSAR and in Matrix 5 of Attachment 10 to PSEG letter dated November 7, 2005.[90] The licensee indicated that the HP and low pressure turbine rotors have been converted to the monoblock design and that the new LP turbine rotors have 21 percent more inertia than the previous design. The licensee indicated that the increase in rotor inertia offsets the effects of the increased steam flow that is required for CPPU operation. The estimated peak speed or "normal overspeed" (NOS) of the main turbine following a full load rejection and subsequent NOS trip while operating at the higher power level is 109.20 percent of rated speed, which compares to 109.26 percent of rated speed for CLTP operation. The licensee indicated that the margin between the NOS value and the mechanical overspeed trip setting, also known as the emergency overspeed (EOS) trip, is normally at least 0.5 percent. The current mechanical overspeed trip setting of 109.9 - 110.4 percent provides a margin of 0.7 percent from the NOS value, which satisfies the stated criterion. The licensee determined that if the NOS trip failed to function, the mechanical trip would limit the speed of the main turbine to an EOS value of 119.35 percent of rated speed; which compares to 119.85 percent of rated speed for CLTP operation. Consequently, because the existing NOS and EOS trip set points will continue to prevent the main turbines from exceeding 120 percent of rated speed during CPPU operation, the licensee concluded that the normal and emergency main turbine overspeed trip set points will continue to be acceptable for CPPU operation.

Contrary to the information that was provided, the NRC staff noted that the Hope Creek UFSAR provided conflicting information relative to overspeed trip protection for the main turbines. The UFSAR descriptive information refers to two electrical trips for the main turbines with trip settings of 108 and 110 percent of rated speed, respectively; but there is no mention of a mechanical overspeed trip. However, UFSAR Table 10.2-1 indicates that the main turbine overspeed trip is 110 percent of rated speed and the backup overspeed trip is 112 percent of rated speed, and the table refers to the overspeed trip as a mechanical trip. The staff requested that the licensee explain the inconsistencies that exist and describe how the main turbines will continue to be protected from overspeed conditions following CPPU implementation such that postulated turbine missile velocity assumptions will remain valid.

The licensee addressed the main turbine overspeed protection inconsistencies in a letter dated May 18, 2007.[91] The licensee indicated that the descriptive information that was provided in UFSAR Section 10.2.2.6, "Overspeed Protection," was correct. The main turbine overspeed protection methods were changed to two electrical overspeed trip devices when the main turbine digital electro-hydraulic control (DEHC) system was installed in February 2005. A primary electrical overspeed trip is initiated if the main turbine reaches approximately 108 percent of rated speed. An emergency electrical overspeed trip that serves as a backup to the

[90] PSEG Letter (LR-N05-0258) to NRC dated November 7, 2005, "Request for License Amendment Extended Power Uprate." ADAMS Accession No. ML053200202

[91] In response to BOP Branch Question 7.14 of PSEG Letter (LR-N07-0114) to NRC dated May 18, 2007, "Response to Request for Additional Information, Request for License Amendment – Extended Power Uprate." ADAMS Accession No. ML071500294

primary trip is initiated at about 110 percent of rated speed. The licensee indicated that the function of the mechanical overspeed trip is now performed by the emergency electrical overspeed trip device and with this correction, the other information that was provided in support of the CPPU LAR is accurate.

Based on a review of the information that was provided, the NRC staff is satisfied 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 analysis 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 turbine missile design-basis considerations. 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 NRC staff agrees that CPPU operation will not result in an increased likelihood that the main turbines will exceed the most limiting design-basis speed that is assumed for turbine missile analyses. The NRC staff notes that the licensee did not request NRC review and approval for using two electric main turbine overspeed trip devices in lieu of using a mechanical and an electrical overspeed trip device as provided in the original plant design and NRC approval of this change was not included within the scope of this evaluation. Consequently, the acceptability of this change relative to satisfying diversity considerations may be subject to future NRC inspection activity.

The licensee has not requested NRC review and approval of any changes to the licensing basis related to the TG for power uprate operation and this evaluation does not constitute NRC approval of any changes to the licensing basis in this regard.

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 turbine and finds that the existing overspeed trip setpoints will continue to prevent the main turbine from exceeding the most limiting overspeed conditions consistent with main turbine missile design-basis considerations. Therefore, the proposed CPPU is considered to be acceptable with respect to the TG.

2.5.1.3 Pipe Failures

Regulatory Evaluation

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

Technical Evaluation

The licensee's evaluation of the impact of postulated HELBs and moderate energy line breaks (MELBs) outside containment is provided in Sections 10.1 and 10.2 of the PUSAR. Because the power uprate is performed at constant pressure with no changes in reactor steam pressure or enthalpy, the effects of postulated HELBs in steam piping will not change for CPPU. For postulated high energy liquid line breaks, the licensee determined that there would be an increase in mass and energy release for breaks in the FW and the RWCU systems, but that the effects are bounded by existing analyses. In particular, the licensee found that for breaks in the RWCU system, RB pressures and temperatures will not exceed allowable values and that while the mass release for breaks in RWCU system piping will increase by 35 percent for CPPU conditions, equipment credited for achieving and maintaining safe shutdown will not be adversely affected.[92] In the case of postulated breaks in the FW system, the licensee determined that the increased energy release will remain bounded by the limiting MSLB. With respect to mass release, the main steam tunnel is the only area of consequence and existing pressure and flooding design limitations will not be exceeded by CPPU conditions.[93] The licensee also determined that the CPPU will not cause additional equipment important to safety beyond what was previously evaluated to be impacted by HELB effects and because CPPU does not alter design pressure limits, flow rates, or system inventories of moderate energy systems, existing MELB analyses will not be affected.

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

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

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed CPPU on the consequences of postulated high and moderate energy pipe failures and finds that protection of SSCs important to safety from the effects of HELBs and MELBs will continue to

[92] Response to BOP Branch Question 7.7 to PSEG Letter (LR-N07-0056) to NRC dated March 22, 2007, "Response to Request for Additional Information, Request for License Amendment – Extended Power Uprate." ADAMS Accession No. ML070930442
[93] Response to BOP Branch Question 7.9 to PSEG Letter (LR-N07-0099) to NRC dated April 30, 2007, "Response to Request for Additional Information, Request for License Amendment – Extended Power Uprate." ADAMS Accession No. ML071290559

satisfy licensing basis-considerations. Therefore, the proposed CPPU is considered to be acceptable with respect to the consequences of postulated high and moderate energy pipe failures outside containment.

2.5.1.4 Fire Protection

Regulatory Evaluation

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

Technical Evaluation

In Nuclear Reactor Regulation (NRR) RS-001, Revision 0, Attachment 1 to Matrix 5, "Supplemental Fire Protection Review Criteria," states that "... power uprates typically result in increases in decay heat generation following plant trips. These increases in decay heat usually do not affect the elements of a FPP related to: (1) administrative controls; (2) fire suppression and detection systems; (3) fire barriers; (4) fire protection responsibilities of plant personnel; and (5) procedures and resources necessary for the repair of systems required to achieve and maintain cold shutdown. In addition, an increase in decay heat will usually not result in an increase in the potential for a radiological release resulting from a fire ... [W]here licensees rely on less than full capability systems for fire events ..., the licensee should provide specific analyses for fire events that demonstrate that: (1) fuel integrity is maintained by demonstrating that the fuel design limits are not exceeded; and (2) there are no adverse consequences on the RPV integrity or the attached piping. Plants that rely on alternative/dedicated or backup shutdown capability for post-fire safe shutdown should analyze the impact of the power uprate on the alternative/dedicated or backup shutdown capability ... The licensee should identify the impact of the power uprate on the plant's post-fire safe-shutdown procedures."

The staff has reviewed PSEG letter dated September 18, 2006,[94] including Attachment 4[95] to this letter. In the analysis for the CPPU in response to Attachment 1 to Matrix 5 of RS-001, the licensee stated the following in Section 6.7 of the *Safety Analysis Report for Hope Creek Constant Pressure Power Uprate* (November 2005):

> …Operation of the plant at the CPPU RTP does not affect the fire suppression or detection systems… These administrative control programs are not affected by CPPU. The safe shutdown systems and equipment used to achieve and maintain cold shutdown conditions do not change, and are adequate for the CPPU conditions. The operator actions required to mitigate the consequences of a fire are not affected… [In response to postulated 10 CFR 50 Appendix R fire events] The results show that the peak fuel cladding temperature, reactor pressure, and containment pressures and temperatures are below the acceptance limits and demonstrate that there is sufficient time available for the operators to perform the necessary actions to achieve and maintain cold shutdown conditions. Therefore, the fire protection systems and analyses are not adversely affected by CPPU… No changes are necessary to the equipment required for safe shutdown for the Appendix R event. One train of systems remains available to achieve and maintain safe shutdown conditions from either the main control room or the remote shutdown panel.

Section 6.7, "Fire Protection," of Attachment 4 to the HCGS LAR satisfactorily addresses these fire protection requirements of the RS-001, Revision 0. The results of the Appendix R evaluation provided in Section 6.7.1 of Attachment 4 presents information that the plant can be brought to cold-shutdown conditions using only safe-shutdown systems and equipment.

In addition, the staff has reviewed the PSEG letter LR-N07-0029, *Supplement to License Amendment Request for Extended Power Uprate*[96]*,* dated February 16, 2007, which contains a revised Appendix R fire event analysis to reflect a plant modification and a change in the time assumed for initiation of suppression pool cooling. The new suppression pool cooling initiation time has been changed from 20 minutes to 60 minutes. The licensee concluded, and the staff agrees, that this change does not affect the ability to achieve and maintain safe shutdown as quoted in NEDC-33076P Revision 2 above.

The licensee's CPPU EPU documentation did not identify changes to design or operating conditions that will adversely impact the post-fire safe-shutdown capability or FPP. The EPU evaluation does not change the credited equipment necessary for post-fire safe-shutdown nor does it reroute essential cables or relocate essential components/equipment credited for post-fire safe-shutdown. The licensee has made no significant changes to the plant configuration or combustible loading as a result of modifications necessary to implement the EPU. The licensee has made no changes and has shown no adverse effects created by the EPU on the fire suppression, detection, or barrier systems. These changes will be evaluated by the licensee under the plant's existing NRC-approved FPP.

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[94] PSEG letter (LR-N06-0286) to NRC dated September 18, 2006, "Request for License Amendment Extended Power Uprate Hope Creek Generating Station Facility Operating License NPF-57 Docket No. 50-354" ADAMS Accession No. ML062680451

[95] Attachment 4 to PSEG letter (LR-N06-0286) to NRC dated September 18, 2006, "Request for License Amendment Extended Power Uprate, Hope Creek Generating Station, Facility Operating License NPF-57, Docket No. 50-354" ADAMS Accession No. ML062680451, LR-N06-0286 - NEDC-33076P, Revision 2) Safety Analysis Report for Hope Creek Constant Pressure Power Uprate (August 2006), Section 6.7 "Fire Protection," and Table 6-4 "Hope Creek Appendix R Fire Event Evaluation Results."

[96] ADAMS Accession No. ML070590182

Conclusion

The NRC staff has reviewed the licensee's fire-related safe shutdown assessment and concludes that the licensee has adequately accounted for the effects of the increased decay heat on the ability of the required systems to achieve and maintain safe shutdown conditions for the 15 percent EPU. The NRC staff further concludes that the FPP will continue to meet the requirements of 10 CFR 50.48, Appendix R to 10 CFR Part 50, and GDC 3 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to fire protection.

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 the current analyses remain valid or have been revised, as appropriate, to properly reflect the proposed EPU conditions. Consequently, the NRC staff's review focuses primarily on any adverse effects that the proposed EPU might have on the assumptions that were used in analyses that were previously completed. Because the impact of the proposed CPPU on fission product control systems and structures are encompassed by the evaluations that are completed in Section 2.6, "Containment Review Considerations," Section 2.7, "Habitability, Filtration, and Ventilation," and Section 2.9, "Source Terms and Radiological Consequences," a separate evaluation in this section is not required.

2.5.2.2 Main Condenser Evacuation System

The main condenser evacuation system (MCES) is a non-safety related system that is used for establishing a vacuum in the condenser during startup and for maintaining the vacuum during normal plant operation. It also removes the non-condensable 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 upon the volume of the condenser and desired evacuation time, neither of which is impacted by the proposed CPPU. Consequently, the existing capability to monitor the MCES effluent is also not affected by the proposed CPPU and therefore, NRC review of the MCES is not required.

2.5.2.3 Turbine Gland Sealing System

The turbine gland sealing system (TGSS) is a non-safety related system that provides sealing steam for the main turbine shafts, the reactor feed pump turbines, 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 modifications are being made to the TGSS that are of consequence and non-condensable gases will continue to be monitored for radiation, the function of the TGSS will not be adversely affected by the proposed power uprate and therefore, an evaluation of the TGSS is not required.

2.5.2.4 Main Steam Isolation Valve Leakage Control System

Because Hope Creek does not have a main steam isolation valve leakage control system, this review section is not applicable.

2.5.3 Component Cooling and Decay Heat Removal

2.5.3.1 Fuel Pool Cooling and Cleanup System

Regulatory Evaluation

The spent fuel pool (SFP) provides wet storage of spent fuel assemblies. The safety function of the fuel pool cooling and cleanup system (FPCCS) 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 FPCCS for the proposed power uprates focused on the effects of the proposed uprate on the capability of the system to provide adequate cooling for the spent fuel during all operating and accident conditions. The criteria that are most applicable to the staff's review of the FPCCS for proposed power uprates are based primarily on GDC 61, "Fuel Storage and Handling and Radioactivity Control," 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 licensing basis considerations that are applicable. The staff's review of the FPCCS is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5. Acceptability for EPU operation is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Section 9.1.3 of the Hope Creek UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

Technical Evaluation

The licensee evaluated the FPCCS in Section 6.3 of the PUSAR for Hope Creek. The components that are necessary for performing the cooling function include two surge tanks, two half-capacity FPC water pumps, two half-capacity fuel pool heat exchangers, and associated piping, valves, and instrumentation. The system also has a cross-connection with the RHR system which allows the RHR system to provide supplemental cooling of the spent fuel. When the RHR system is operated in parallel with the FPCCS to provide FPC during a full core offload, one RHR pump takes its suction either from the skimmer surge tanks or from the reactor vessel via the shutdown cooling (SDC) suction piping, circulates the water through one RHR heat exchanger, and returns it to the SFP via the two RHR inter-tie return diffusers.

UFSAR Section 9.1.3.1 indicates that the FPCCS is designed to maintain pool temperature less than or equal to 135°F following a batch core offload (approximately one third of the core) at the end of a fuel cycle assuming a limiting heat load with all other fuel storage locations filled from previous refuelings. This limiting heat load is currently 16.1×10^6 British thermal units per hour (BTU/hr) at 10 days after reactor shutdown. The licensee determined that the new limiting heat load for CPPU operation is 17.2×10^6 BTU/hr at 10 days after shutdown.[97] The licensee stated that the two FPCCS heat exchangers were modified in 1990 from 72 plates to 99 plates per heat exchanger, which increased the design heat transfer capability of each FPCCS heat exchanger from 6.0×10^6 BTU/hr to 9.5×10^6 BTU/hr for a combined heat transfer capability of 19×10^6 BTU/hr. Therefore, the SFP heat load for CPPU operation is well within the combined design heat transfer capability of the FPCCS heat exchangers eight days after shutdown, and the licensing-basis criterion to maintain the SFP temperature less than or equal to 135°F following a batch core offload will continue to be satisfied following CPPU implementation.

[97] Response to BOP Branch Question 7.1 in PSEG letter (LR-N07-0056) to NRC dated March 22, 2007, "Response to Request for Additional Information Request for License Amendment - Extended Power Uprate" ADAMS Accession No. ML070930442

UFSAR Section 9.1.3.1 indicates that the FPCCS is designed to permit the RHR system to be operated in parallel with the FPCCS to maintain pool temperature less than or equal to 150°F following a full core offload at the end of a fuel cycle assuming a limiting heat load with all other fuel storage locations filled from previous refuelings. This limiting heat load is 34.2x10^6 BTU/hr at 10 days after reactor shutdown. The licensee determined that the new limiting heat load for CPPU operation is 43.0x10^6 BTU/hr (full core offload) 10 days after shutdown. The licensee indicated that the RHR heat exchanger design heat removal capacity is 41.6x10^6 BTU/hr at the limiting SFP temperature of 150°F and 30.2x10^6 BTU/hr at a SFP temperature of 135°F. As previously stated, the FPCCS can remove 19x10^6 BTU/hr with a SFP temperature of 135°F. The heat transfer capabilities of the RHR and FPCCS heat exchangers are higher when the SFP temperature is heated to 150°F and, therefore, the combined SFP heat removal capability that is available for full core offloads well exceeds the limiting SFP heat load for CPPU operation.

The current licensing basis for single failure as stated in UFSAR Section 9.1.3.6 for the normal maximum heat load (i.e. 16.1x10^6 BTU/hr at CLTP for the batch core offload) allows bulk water temperature in the SFP to reach 152 °F if RHR assist is unavailable and one FPCCS pump is not available or 174°F if RHR assist is unavailable and one FPCCS pump and one FPCCS heat exchanger are not available. The licensee indicated[98] that Hope Creek will continue to meet these temperature limitations for CPPU given these assumed failures and the increased heat load of 17.2x10^6 BTU/hr due to the modifications that were made previously to the FPCCS heat exchangers as described above. Also, in the unlikely event of a complete loss of spent FPC during CPPU operation, the licensee indicated that the SFP will not begin to boil for at least 5 hours for the most limiting full core offload case (Section 6.3 of the PUSAR). The licensee also indicated that the maximum boil-off rate of 130 gallons per minute (gpm) is less than the capacity of each of the three seismic Category 1 emergency makeup sources: the service water system (SWS), the LP injection system, and the emergency fire makeup system. Somewhat inconsistent with this, the NRC staff noted that UFSAR Page 9.1-3 indicates that SFP makeup is from the seismic Category 1 Station Service Water System (SSWS), and a seismic category 1 fire hose fill connection is available as a backup source. The licensee addressed this apparent inconsistency in a letter dated August 31, 2007,[99] indicating that the information in the PUSAR is correct.

Based on a review of the information that was provided, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the potential impact of the proposed power uprate on the capability of the FPCCS (with the assistance of RHR for full core offload) to adequately cool the spent fuel. The licensee has determined that the existing design heat removal capacity of the FPCCS and RHR system (as applicable) will continue to exceed the maximum SFP heat load for CPPU operation, and the time to boil following a loss of SFP cooling for the most limiting full core offload case will continue to afford plant operators sufficient time to take corrective actions. 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.

[98] Response to BOP Branch Question 7.3 in PSEG letter (LR-N07-0056) to NRC dated March 22, 2007, "Response to Request for Additional Information Request for License Amendment - Extended Power Uprate" ADAMS Accession No. ML070930442

[99] Response to BOP Branch Question 7-19 in PSEG letter (LR-N07-0223) to NRC dated August 31, 2007, "Response to Request for Additional Information Request for License Amendment - Extended Power Uprate" ADAMS Accession No. ML072540651

The licensee has not requested NRC review and approval of any changes to the licensing basis related to the FPCCS for power uprate operation and this evaluation does not constitute NRC approval of any changes that are being made to the licensing basis in this regard.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the impact that the proposed CPPU will have on the FPCCS and finds that the FPCCS 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 NRC 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 SWS provides essential cooling for safety-related equipment and may also provide cooling for non-safety 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 EPU will have on the capability of the SWS to perform its safety functions. The criteria most applicable to the NRC staff's review of the SWS 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 licensing-basis considerations that are applicable. The NRC staff's review of the SWS is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5, and acceptability for EPU operation is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Section 9.2.1 of the Hope Creek UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

Technical Evaluation

The licensee's evaluation of the SWS is provided in Section 6.4.1.1.1 of the PUSAR. The SWS provides essential cooling for the safety auxiliary cooling system (SACS) heat exchangers and non-essential cooling for the reactor auxiliary cooling system (RACS) heat exchangers during normal plant operating and loss of offsite power (LOOP). During postulated loss of coolant accidents (LOCAs) and other DBAs, the SWS only provides cooling water to the SACS heat exchangers. The licensee indicated[100] that the maximum allowed SWS supply temperature as specified by Technical Specification 3.7.1.3, "Ultimate Heat Sink," was established based upon CPPU operating conditions as approved by the NRC staff in License Amendment 168[101] and consequently, temperature limitations of SSCs important to safety that are cooled by the SWS will not be exceeded following CPPU implementation. The licensee confirmed that the programmatic controls that were established in response to GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment," and that the resolution of GL 96-06, "Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions," will continue to be adequate for CPPU operation.

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[100] Response to BOP Branch Question 7.10.e in PSEG letter (LR-N07-0099) to NRC dated April 30, 2007, "Response to Request for Additional Information Request for License Amendment - Extended Power Uprate" ADAMS Accession No. ML071290559
[101] ADAMS Accession No. ML062130012

Based on a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated the impact of the proposed CPPU on the capability of the SWS to perform its safety functions. Because design limitations of SSCs will not be exceeded and licensing-basis considerations will continue to be satisfied as established by the staff's review and approval of License Amendment 168, the staff agrees that the capabilities of the SWS will not be impacted by the proposed power uprate. Additionally, existing GL 89-13 programmatic controls will continue to assure that heat exchanger performance is maintained consistent with licensing-basis considerations following CPPU implementation. Also, because the drywell coolers for Hope Creek are non-safety related and their use is strictly controlled by the emergency operating procedures (EOPs) in order to prevent the occurrence of waterhammer following postulated accident conditions, the licensee's resolution of the GL 96-06 waterhammer and two-phase flow issues are not affected by the proposed CPPU.

The licensee has not requested NRC review and approval of any changes to the licensing basis related to the SWS for power uprate operation and this evaluation does not constitute NRC approval of any changes that are being made to the licensing basis in this regard.

Conclusion

The NRC staff has reviewed the licensee's assessment of the impact that the proposed CPPU will have on the SWS 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 to be acceptable with respect to the SWS.

2.5.3.3 Safety Auxiliary Cooling Water System

Regulatory Evaluation

The safety auxiliary cooling water system (SACS) circulates water to remove heat from SSCs important to safety during plant operation, cool down, and post-accident conditions. The SACS consists of two redundant loops, A and B, with two 50 percent capacity pumps and two 50 percent capacity heat exchangers per loop. Major SACS heat loads include the RHR heat exchangers, EDG coolers, SFP heat exchangers, and the control room chillers. The NRC staff's review for proposed power uprates focuses on the continued capability of the SACS to provide adequate cooling for critical plant equipment in accordance with the SACS licensing basis. The criteria most applicable to the staff's review of the SACS are based on GDC 44, "Cooling Water," 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 licensing-basis considerations that are applicable. The staff's review of the SACS is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5, and acceptability for EPU operation is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Section 9.2 of the Hope Creek UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

Technical Evaluation

The licensee's evaluation of the SACS is provided in Sections 6.4.1.1.1 and 6.4.1.1.2 of the Hope Creek PUSAR as supplemented by RAI responses.[102] [103] The information provided in PUSAR Sections 6.4.1.1.1 and 6.4.1.1.2 indicated that: a) CPPU LOCA heat loads will not be increased over CLTP values, and b) the CLTP LOCA calculation was overly conservative by assuming the maximum SFP heat load immediately following a full core offload. The licensee subsequently corrected this information[104] by providing a markup of UFSAR Table 9.2-4 which shows that the LOCA heat loads increase for CPPU operation and that the SFP heat load at 10 days after shutdown was used in the calculation and not the heat load immediately following the full core offload.

The licensee determined that the LOCA establishes the most limiting scenario for SACS cooling heat loads and that the only heat loads that are affected by CPPU operation are the RHR heat exchangers, the ECCS room coolers, and the SFP heat exchangers. The licensee found that the total increase in the SACS heat load for CPPU conditions was less than would be expected primarily because the ANS/ANSI 5.1-1979 methodology was used for calculating the decay heat load in the reactor vessel instead of the May-Witt model that was used previously.

Consequently, the single train SACS heat load for the limiting LOCA event increases less than 7 percent for CPPU operating conditions. In accordance with plant operating procedures and as approved by the NRC staff,[105] the licensee can temporarily suspend cooling to the SFP (approximately 8 percent of the single train SACS LOCA heat load 10 days after shutdown) for up to 24 hours, provided the SFP temperature remains below 130°F. This temperature limit is necessary to ensure that the limiting SACS supply temperature of 100°F will not be exceeded following a LOCA. Given this operational flexibility, the staff agrees that the SACS system will remain capable of performing its safety functions following CPPU implementation.

Based on a review of the information that was provided, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of CPPU on the capability of the SACS to perform its specified safety functions. The licensee has confirmed that the proposed CPPU will not cause SACS design limitations to be exceeded and that the capability to accommodate the specified heat loads in accordance with the plant licensing basis will not be affected by the proposed power uprate. The staff's evaluation of GL 89-13 and GL 96-06 considerations is provided in the previous section.

The licensee has not requested NRC review and approval of any changes to the licensing basis related to SACS for power uprate operation and this evaluation does not constitute NRC approval of any changes that are being made to the licensing basis in this regard.

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[102] Response to BOP Branch Question 7.5 in PSEG letter (LR-N07-0056) to NRC dated March 22, 2007, "Response to Request for Additional Information Request for License Amendment - Extended Power Uprate" ADAMS Accession No. ML070930442
[103] Response to BOP Branch Question 7.10 in NRC Staff Review of GE Nuclear Energy Licensing Topical Report, NEDC-33004P, Revision 3, "Constant Pressure Power Uprate," dated March 31, 2003. ADAMS Accession No. ML031190318
[104] Response to BOP Branch Question 7.10 in PSEG letter (LR-N07-0099) to NRC dated April 30, 2007, "Response to Request for Additional Information Request for License Amendment - Extended Power Uprate" ADAMS Accession No. ML071290559
[105] Paragraph 3.1.1.2 in NRC Letter (Enclosure 2 Safety Evaluation) from Richard B. Ennis to Mr. Harold Kaiser, Public Service Electric and Gas, "Hope Creek Generating Station, Issuance of Amendment, Ultimate Heat Sink Temperature Limits (TAC No. MA2060) " dated April 19, 1999 ADAMS Accession No. ML011770031

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed CPPU on the SACS and concludes that the licensee has adequately accounted for the increased heat loads from the proposed CPPU on system performance. The NRC staff concludes that SACS will continue to be capable of performing equipment cooling and DHR functions in accordance with licensing-basis considerations. Based on the above, the NRC staff finds the proposed CPPU acceptable with respect to the safety and auxiliary cooling water system.

2.5.3.4 Ultimate Heat Sink

The ultimate heat sink (UHS) provides the cooling medium for dissipating the heat removed from the reactor and its auxiliaries during normal operation, refueling, transient, and accident conditions. The Delaware River serves as the UHS for Hope Creek and provided that existing TS water level and temperature requirements continue to be satisfied, the amount of water available far exceeds that required for dissipating shutdown and accident heat loads. Note that UHS temperature and level considerations relative to CPPU operation are evaluated primarily in Sections 2.5.3.1, 2.5.3.2, and 2.5.3.3. Therefore, the UHS is unaffected by the proposed power uprate.

2.5.4 Balance-of-Plant Systems

2.5.4.1. Main Steam

The main steam supply system (MSSS) transports steam from the NSSS to the power conversion system and to various auxiliary steam loads. The NRC staff's review of the MSSS for proposed power uprates focuses primarily on any changes in the design or operation of the MSSS that could impact the capability of steam-driven equipment to function in accordance with safe shutdown and accident analysis assumptions, impact the capacity of the steam dump system, or could otherwise result in increased off-site releases or challenges to reactor safety systems. Because no changes of this nature are being made, 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), and 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 of the MCS for proposed power uprates focuses primarily on the capability of the main condensers to accommodate the steam bypass flow rates and on any changes that are being made to the MSIV bypass leakage pathway to confirm that the isolation boundary has been properly established. Because the proposed CPPU will not affect the steam bypass flow rate and MSIV bypass leakage pathway boundaries are also not affected, this area of review is not affected by the proposed power uprate. Therefore, an evaluation of the MCS is not required.

2.5.4.3 Turbine Bypass

The turbine bypass system (TBS) is a non-safety related system designed to discharge a stated percentage of rated main steam flow directly to the main condenser, bypassing the turbine and enabling the plant to take step-load reductions up to the capacity of the TBS without causing the reactor or turbine to trip. The NRC staff review of the TBS for proposed power uprates focuses primarily on any modifications that are being made to the TBS that may warrant the performance of confirmatory testing. Because changes are not being made in the design and operation of the TBS for CPPU operation, an evaluation of the TBS is not required.

2.5.4.4 Condensate and Feedwater

Regulatory Evaluation

The condensate and feedwater system (CFS) provides FW at a particular temperature, pressure, and flow rate to the reactor. The scope of review in this section includes the part of the CFS that is outside containment beyond the outermost containment isolation valves. While the CFS does not perform a safety function, marginal system design and operational capability could result in loss of FW 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 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 loss of FW event occurrences. The staff's review of the CFS is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5, and acceptability for EPU operation is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Section 10.4.7 of the Hope Creek UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

Technical Evaluation

The licensee's evaluation of the CFS for CPPU operation is provided in Section 7.4 of the PUSAR. The licensee indicated that the three reactor feedwater pumps (RFPs), primary condensate pumps (PCPs) and secondary condensate pumps (SCPs) will continue to operate within nameplate data following CPPU implementation and no pump modifications are required except increasing the time delay for the suction pressure trip of the SCPs. The licensee also determined that existing RFP turbine speed limit setpoints will continue to be adequate for CPPU operation and thus, the maximum postulated RFP runout is not affected by the proposed power uprate.

The Hope Creek licensing basis, as reflected in Section 10.4.7 of the UFSAR, states that the CFS is designed to permit continued plant operation at a reduced power level, without a reactor trip, following a failure of a RFP, PCP, or SCP, or a string of FW heaters. Because the CFS will be operating with reduced flow margins and consistently with this provision of the plant licensing basis, the NRC staff requested that the licensee demonstrate by analyses or transient testing, or a combination of these, that the loss of a single RCP, PCP, or SCP will not result in a total loss of reactor FW. The licensee responded to the staff's request[106] indicating that there is no potential for a total loss of FW due to a single RFP, PCP, or SCP trip at CPPU conditions. The licensee's assessment was based on a combination of transient analyses that were performed showing that there is sufficient suction pressure margin at the RFPs and SCPs to avoid any additional RFP trips. The plant's response to actual trips of an RFP and an SCP were used in support of these analyses. In order to ensure that a trip of a PCP will not cause a trip of a SCP, the licensee determined (response to Question 7.18) that the existing SCP suction pressure trip time delays should be increased and staggered between 10 and 15 seconds. Based on a review of the information that was presented by the licensee, and recognizing that CFS modifications are minimal for CPPU operation, the NRC staff agrees that a loss of a single RFP, SCP, or PCP should not result in a complete loss of FW.

Based on a review of the information that was provided, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability and reliability of the CFS to provide reactor FW for CPPU operation. Because the CFS modifications that are required for implementing the proposed power uprate do not have much impact on the existing CFS transient behavior such that transient analyses for CPPU operation could be performed and compared to the CFS transient response that was observed following a RFP and SCP trip, the NRC staff agrees that pump trip testing at the CPPU power level is not necessary to demonstrate acceptable performance. The NRC staff also agrees that with the planned modification to increase and stagger the time delays of the low suction pressure SCP trips, the CFS should continue to reliably supply reactor FW following CPPU implementation without causing an increase in the frequency of total loss of FW events.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed power uprate on the CFS and finds that the CFS will remain capable of satisfying the reactor FW demands for CPPU operation and in particular, that CPPU operation will not cause the frequency of total loss of FW events to increase. Therefore, the CFS will continue to satisfy licensing-basis considerations and the proposed power uprate is considered to be acceptable with respect to the CFS.

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[106] Response to BOP Branch Questions 7.13, 7.16, 7.17, and 7.18 in PSEG letter (LR-N07-0114) to NRC dated May 18, 2007, "Response to Request for Additional Information Request for License Amendment - Extended Power Uprate" ADAMS Accession No. ML071500294 and PSEG letter (LR-N07-0154) to NRC dated June 22, 2007, "Response to Request for Additional Information Request for License Amendment - Extended Power Uprate" ADAMS Accession No. ML071840167

2.5.5 Waste Management Systems

2.5.5.1 Gaseous Waste Management Systems

Regulatory Evaluation

The gaseous waste management system (GWMS) include those systems that process potential sources of airborne releases of radioactive gases during normal operation and AOOs. These systems typically include the off-gas system, the condenser air removal system, the gland seal exhaust, and building ventilation system exhausts. The NRC staff's review of the GWMS focuses on the effects that the proposed EPU may have on: (1) the design criteria of the gaseous waste management systems; (2) methods of treatment; (3) expected releases; (4) principal parameters used in calculating the releases of radioactive materials in gaseous effluents; and (5) design features for precluding the possibility of an explosion if the potential for explosive mixtures exists. 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, 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 values; (2) GDC-3, insofar as it requires that (a) SSCs important to safety be designed and located to minimize the probability and effect of fires, (b) noncombustible and heat resistant materials be used, and (c) fire detection and fighting systems be provided and designed to minimize the adverse effects of fires on SSCs important to safety; (3) GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents; (4) GDC-61, insofar as it requires that systems that contain radioactivity be designed with appropriate confinement; and (5) 10 CFR Part 50, Appendix I, Sections II.B, II.C, and II.D, which set numerical guides for design objectives and limiting conditions for operation to meet the "as low as is reasonably achievable" (ALARA) criterion. The staff's review of the GWMS is performed in accordance with the guidance in Section 2.1 of RS-001, Matrix 5; and acceptability for EPU operation is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Section 11.3 of the Hope Creek UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

Technical Evaluation

As discussed in Section 8.2 of the Hope Creek 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 absorber inlet dew point, and charcoal absorber temperature. **[[**

.]] However, the power uprate has a secondary effect in that any fuel pin leaks will release greater quantities of fission gasses and a greater fraction of condenser in-leakage will be activated by the higher average neutron flux. But these secondary effects are negligible in comparison with variations in the primary contributors to gaseous radiological effluents. Consequently, only the catalytic recombiner temperature and offgas condenser heat load are of interest. Because the Hope Creek 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 that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated the impact of the proposed CPPU 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 staff agrees that the GWMS will continue to satisfy the plant licensing basis following implementation of CPPU.

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 to be acceptable with respect to the GWMS.

2.5.5.2 Liquid Waste Management Systems

Regulatory Evaluation

The liquid waste management system (LWMS) is designed to collect, store, process, and dispose of or recycle all radioactive or potentially radioactive liquid waste generated by plant operation or maintenance. Major components include floor and equipment drains, transfer pumps, and various waste system tanks. The NRC staff's review of the LWMS focuses on the effects that the proposed EPU 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 the LWMS are based on: (1) 10 CFR 20.1302, insofar as it places specific limitations on the annual average concentrations of radioactive materials released at the boundary of the unrestricted area; (2) 10 CFR Part 50, Appendix I, Sections II.A and II.D, which set numerical guides for dose design objectives and limiting conditions for operation to meet the ALARA criteria; and (3) other licensing basis considerations that are applicable. The staff's review of the LWMS is performed in accordance with the guidance in Section 2.1 of RS-001, Matrix 5, and acceptability for EPU operation is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Section 11.2 of the Hope Creek UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

Technical Evaluation

As discussed in Section 8.1 of the 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 pre-filters (CPFs). More frequent CPF backwashing will be necessary due to the increased condensate flow that will be required for CPPU operation. The licensee estimated that the resultant increase in liquid radiological waste is insignificant 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 that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the LWMS to perform its functions. Because the increase in additional radioactive waste being generated due to CPPU operation is expected to be minimal and well within the capacity of the LWMS, 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 to be 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 the wet waste dewatering and liquid collection processes, and focuses on the impact that the proposed power uprate will have on the release of radioactive material to the environment via gaseous and liquid effluents. Because Sections 2.5.5.1 and 2.5.5.2 fully encompass these considerations, a separate evaluation of solid waste management systems 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[107] that the electrical rating and loading of the EDGs are not altered by the proposed CPPU and consequently, the fuel oil consumption rate and fuel oil storage requirements are not affected. Therefore, an evaluation of the EDG fuel oil storage requirements for the proposed power uprate is not required.

[107] Response to BOP Branch RAI 7.8 in PSEG letter (LR-N05-0258) to NRC dated November 7, 2005, "Request for License Amendment Extended Power Uprate" ADAMS Accession No. ML053200202

2.5.6.2 Light Load Handling System (Related to Refueling)

The light load handling system (LLHS) includes components and equipment used for handling new fuel at the receiving station and for loading spent fuel into shipping casks. The licensee is not introducing a new fuel design in conjunction with the proposed CPPU and as indicated in Table 6.5 of the PUSAR, cranes, hoists, and fuel handling systems are not affected by the proposed power uprate. Because this area of review is not affected by the proposed power uprate, an evaluation of the LLHS is not required.

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 for the primary containment functional design covered: (1) the temperature and pressure conditions in the drywell and wetwell due to a spectrum of postulated LOCAs; (2) the differential pressure across the operating deck for a spectrum of LOCAs; (3) suppression pool dynamic effects during a LOCA or following the actuation of one or more RCS safety/relief valves; (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 safety/relief valve 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, insofar as it requires that the reactor containment be provided to establish an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment; (3) GDC-50, 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, 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, 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. Specific review criteria are contained in SRP Section 6.2.1.1.C and other guidance provided in Matrix 6 of Power Uprate Review Standard RS-001.[108]

Technical Evaluation

The Hope Creek primary containment, as described in Section 6.2 of the Hope Creek UFSAR[109] is a Mark I design consisting of: (1) a drywell which encloses the reactor vessel, the RCS and other branch connections to the RCS; (2) a toroid-shaped pressure suppression chamber (or wetwell) partially filled with a large volume of water (the suppression pool) which is the primary source of water for the ECCS low head pumps; (3) a vent system connecting the drywell atmosphere to the suppression chamber; (4) containment isolation valves; (5) containment cooling systems; and (6) other equipment.

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[108] ADAMS Accession No. ML033640024

[109] Hope Creek Generating Station Updated Final Safety Analysis Report, Revision 14, dated July 26, 2005. ADAMS Accession No. ML052220616

The proposal to operate Hope Creek at the requested EPU using BWR generic CPPU methods requires that safety analyses for those design basis accidents 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 reactor vessel SRVs and their discharge into the suppression pool.

Short-term and long-term containment analyses results are reported in the Hope Creek UFSAR. The short-term analysis is directed primarily at determining the drywell pressure response during the initial blowdown of the reactor vessel inventory to the containment following a large break 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 are discussed in the licensee's submittals and evaluated below.

Short-term LOCA Analysis

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 62 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 wetwell occur. These analyses were performed at 2 percent above 3952 MWt. This power is 20 percent greater than original rated thermal power and is therefore conservative for this application. The 2 percent accounts for instrument uncertainties in conformance with the guidance of Regulatory Guide 1.49, Revision 1, December 1973.[110] The licensee used analysis methods approved for CPPUs. The licensee used the LAMB computer code[111] for the short-term mass and energy release and the M3CPT computer code[112] for the containment response. The power uprate methods approved by the NRC[113] permit the use of either the M3CPT computer code or the LAMB computer code to calculate the mass and energy release from a postulated pipe break into the drywell.[114]

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[110] ADAMS Accession No. ML003740132

[111] GE Nuclear Energy, "General Electric Model for LOCA Analysis in Accordance with 10 CFR 50 Appendix K," NEDE-20566-P-A, September 1986

[112] The General Electric Mark III Pressure Suppression Containment System Analytical Model," NEDO 20533, June 1974

[113] NRC Staff Review of GE Nuclear Energy Licensing Topical Report, NEDC-33004P, Revision 3, "Constant Pressure Power Uprate," dated January 17, 2008. ADAMS Accession No. ML073340231

[114] GE Nuclear Energy, Topical Report, NEDC-32424P-A, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," February 1999 (Proprietary. ADAMS Accession No. ML003680231

The results of these analyses at EPU and the corresponding design limits are provided in Table 4-1 of the PUSAR.[115] The short-term portion of this table is reproduced below.

HOPE CREEK SHORT-TERM CONTAINMENT PERFORMANCE RESULTS

Parameter	Current (3359MWt)	2 % above 3952 MWt (20% of OLTP)	Design Limit
Peak Drywell Pressure (psig)	47.6	50.6	62
Peak Drywell Air Space Temperature (°F)	295	298	340

The current UFSAR containment performance results are based on reactor power of 3359 MWt, which is 101.4 percent of CLTP (3339 MWt). The table compares the peak pressure and temperature at 3359 MWt and at 2 percent above 3952 MWt, which is 20 percent above the OLTP. This comparison isolates the effect of the power uprate on the peak drywell pressure and peak drywell airspace temperature. The design limits are also shown. The results of these calculations show that the peak drywell pressure and temperature at EPU conditions remain below the respective design limits.

P_a is defined in 10 CFR Part 50, Appendix J, as the calculated peak containment internal pressure related to the design basis LOCA. Containment leakage rate testing is performed at P_a or a multiple of P_a. P_a increases to a value of 50.6 psig as a result of the EPU but is less than the drywell and wetwell design pressures of 62 psig. The licensee proposed to revise P_a in the Hope Creek TSs 3.6.1.2 and 6.8.4.f to 50.6 psig. The staff finds this acceptable since P_a is determined with acceptable methods and assumptions.

Based on the use of acceptable calculation methods and conservative assumptions, and results less than the design containment pressure and temperature, the Hope Creek short-term containment pressure and temperature responses at EPU are acceptable.

Long-term LOCA Analysis

The long-term LOCA analysis was performed for the Hope Creek design basis LOCA at 2 percent above the Hope Creek EPU rated thermal power (3917 MWt). The SHEX computer code[116] 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. The licensee used the ANSI/American Nuclear Society (ANS) 5.1-1979 decay heat model with a 2 sigma (σ) uncertainty added.[117] The licensee

[115] Attachment 4 to PSEG letter (LR-N06-0286) to NRC dated September 18, 2006, “Request for License Amendment Extended Power Uprate, Hope Creek Generating Station, Facility Operating License NPF-57, Docket No. 50-354” ADAMS Accession No. ML062680451

[116] MC3PT: "The General Electric Mark III Pressure Suppression Containment Analytical Model," NEDO-20533, General Electric Company, June 1974 and Supplement 1, September 1975.

[117] Shrock, V.E., A Revised ANS Standard for Decay Heat From Fission Products, Nuclear Technology, Volume 46, Page 323,

incorporated the guidance of Service Information Letter 636, Revision 1[118] which recommends accounting for additional actinides and activation products which further increases the predicted decay heat.

The long-term LOCA analysis demonstrates that the peak suppression pool temperature and wetwell pressure remain below their respective design limits. The results of these analyses and the acceptance criteria are provided in Table 4 -1 of the PUSAR.[119] The relevant portions of this table are reproduced below.

HOPE CREEK LONG-TERM CONTAINMENT PERFORMANCE RESULTS

Parameter	CLTP (3339MWt)	@ 2 % above EPU (3917 MWt)	Design Limit
Peak Bulk Pool Temperature for Design Basis LOCA (°F)	201	212.3	310
Long-term Peak Wetwell Pressure for Design Basis LOCA (psig)	27.6	27.7	62

The EPU peak suppression pool temperature of 212.3°F is slightly greater (0.3°F) than the current licensing limit of 212°F discussed in Hope Creek UFSAR, Section 6.2.1.1.3.1,[120] but remains below the design limit of 310°F. The licensing limit of 212°F is not a design limitation. Therefore, exceeding this limit does not affect any physical barrier.

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 actuation of an SRV or valves. BWR Mark I containment analytical and empirical methods,[121] approved by the staff in NUREG-0661, “Safety Evaluation Report Mark I Containment Long-Term Program Resolution of Generic Activity A-7,” July 1980,[122] were used by the licensee to address these issues for Hope Creek and to develop

1979; and ANSI/ANS 5.1-1979: Decay Heat Power in Light Water Reactors, Hinsdale, IL, American Nuclear Society, 1979.

[118] Service Information Letter No. 636, “Additional Terms Included in Reactor Decay Heat Calculations,” Revision 1, General Electric Nuclear Energy, June 6, 2001.

[119] Attachment 4 to PSEG letter (LR-N06-0286) to NRC dated September 18, 2006, “Request for License Amendment Extended Power Uprate, Hope Creek Generating Station, Facility Operating License NPF-57, Docket No. 50-354” ADAMS Accession No. ML062680451

[120] Hope Creek Generating Station Updated Final Safety Analysis Report, Revision 14, dated July 26, 2005. ADAMS Accession No. ML052220616

[121] General Electric Company, Mark I Containment Program Load Definition Report," General Electric Topical Report NEDO-21888, Revision 2, November 1981

[122] Safety Evaluation Report, Mark I Containment, Long-Term Program, “Resolution of Generic Technical Activity A-7,” USNRC, NUREG 0661, July 1980. ADAMS Accession No. ML072710452

a plant-unique structural evaluation which was submitted to the NRC in 1984[123] and supplemented in 1985.[124]

The licensee, as part of the Hope Creek EPU evaluation, calculated the LOCA hydrodynamic loads at CPPU conditions. The licensee stated that the calculations were performed at 102 percent of 3952 MWt (120 percent of OLTP) using previously approved methods.[125] The licensee did use a more detailed model of the RPV[126] which has previously been accepted by the NRC for containment mass and energy release calculations, including EPUs. These analyses provide the important parameters for the calculation of the blowdown loads (drywell and wetwell pressure, vent flow rates and the suppression pool temperature).

The licensee states that the short-term containment response to a LOCA blowdown at 2 percent above 3952 MWt (20 percent above OLTP) is within the range of conditions used to define the pool swell, CO, chugging loads for the plant. The vent thrust loads are less than the values used during the Mark I long-term program since the LAMB code is used for the blowdown flows and enthalpies rather than the M3CPT code.

The licensee’s evaluation of containment hydrodynamic loads as a result of a LOCA are in accordance with the CLTR[127] and previously approved methods and are therefore conservative and acceptable for the EPU.

Loads Due to Safety Relief Valve (SRV) Discharge

The dynamic loads on the suppression pool due to the discharge of steam from SRVs are part of the containment design basis. The SRV discharge loads are evaluated for two cases: initial actuation and re-actuation. Since the SRV setpoints remain unchanged, the initial actuation loads are unchanged.

Subsequent actuation loads may be affected by changes in the SRV discharge line water level and pool water temperature (in addition to design characteristics which remain unchanged by the Hope Creek EPU). Hope Creek employs Low-Low Set logic which mitigates the potential adverse effects of subsequent SRV actuations due to a higher water level in the SRV discharge line after the first actuation. The licensee states that analysis at 102 percent of 3952 MWt shows that there is at least 18 seconds to reopen an SRV. This time is sufficient to allow the water leg of the SRV discharge line to clear before a subsequent SRV actuation. This, in turn, maintains thrust loads on the SRV piping within bounds of the first SRV actuation. Therefore, the Hope Creek EPU is acceptable with respect to SRV initial and subsequent actuations.

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[123] Letter from Robert L. Mittl, General Manager, Nuclear Assurance and Regulation, Public Service Electric and Gas Company, to USNRC, Hope Creek Generating Station, Plant Unique Analysis Report, February 10, 1984

[124] Letter from Robert L. Mittl, General Manager, Nuclear Assurance and Regulation, Public Service Electric and Gas Company, to USNRC, Hope Creek Generating Station, request for Additional information - HCGS PUAR, January 31, 1985

[125] General Electric Company, Mark I Containment Program Load Definition Report," General Electric Topical Report NEDO-21888, Revision 2, November 1981

[126] GE Nuclear Energy, "General Electric Model for LOCA Analysis in Accordance with 10 CFR 50 Appendix K," NEDE-20566-P-A, September 1986

[127] General Electric (GE) Licensing Topical Report (LTR) NEDC-33004P-A, “Constant Pressure Power Uprate,” Revision 4, dated July 31, 2003. ADAMS Accession No. ML032170332

NUREG-0783, “Suppression Pool Temperature Limits for BWR Containments,”[128] sets forth criteria limiting local pool temperature limits following SRV discharges. The licensee states that the local pool temperature has been evaluated for EPU operating conditions. The local peak suppression pool temperature is 202.1°F which is below the limit of 204.1°F.[129]

Instrumentation

The licensee did not report any changes caused by the EPU affecting containment instrumentation for monitoring containment variables including the containment atmosphere.

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 GDCs 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 for subcompartment analyses covered the determination of the design differential pressure values for containment subcompartments. The NRC staff’s review focused on the effects of the increase in mass and energy release into the containment due to Hope Creek EPU operating conditions, and the resulting increase in pressurization. The NRC’s acceptance criteria for subcompartment analyses are based on: (1) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, and that such SSCs be protected against dynamic effects; and (2) GDC-50, insofar as it requires that containment subcompartments be designed with sufficient margin to prevent fracture of the structure due to the calculated pressure differential conditions across the walls of the subcompartments. Specific review criteria are contained in SRP Section 6.2.1.2 and other guidance provided in Matrix 6 of Power Uprate Review Standard RS-001.[130]

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[128] T. M. Su, “Suppression Pool Temperature Limits for BWR Containments,” USNRC, NUREG-0783, November 1981. ADAMS Accession No. ML031080532
[129] GE Nuclear Energy, Hope Creek Generating Station Suppression Pool Temperature Response, NEDC-30154, June 1983
[130] ADAMS Accession No. ML033640024

Technical Evaluation

The Hope Creek UFSAR[125] states that the Hope Creek containment subcompartments are the RPV shield annulus and the drywell head region.

The licensee states that the recirculation suction line break and the FW line break cases evaluated for anticipatory reactor trip system maximum extended load line analysis (ARTS/MELLA) bound the Hope Creek EPU mass and energy releases for AP. The methodology change to ARTS/MELLA has a much greater impact on both current licensed thermal power loads and Hope Creek EPU loads than the impact of increased power level.

For the EPU, the licensee assumed the same limiting annulus line break which is a recirculation suction line break. The licensee assumed a less limiting flow split between the containment and the annulus. Appendix 6B reports that subsequent to the FSAR analysis which assumed a 50/50 percent (containment/annulus) flow split, a flow diverter was installed which changed the flow split to 75/25 percent. The Hope Creek UFSAR[131] analysis was not revised. However, for the EPU analysis, the licensee has revised the flow split to the less conservative value. Since the 75/25 percent flow split is based on the actual construction of the plant, its use is 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 NRC staff concludes that containment SSCs important to safety will continue to be protected from the dynamic effects resulting from pipe breaks and that the subcompartments will continue to have sufficient margins to prevent fracture of the structure due to pressure difference across the walls following implementation of the proposed Hope Creek EPU. Based on this, the NRC staff concludes that the plant will continue to meet GDCs 4 and 50 for the proposed Hope Creek EPU. Therefore, the NRC staff finds the proposed Hope Creek 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) 10 CFR Part 50, Appendix K, insofar as it identifies sources of energy

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[131] Hope Creek Generating Station Updated Final Safety Analysis Report, Revision 14, dated July 26, 2005. ADAMS Accession No. ML052220616

during a LOCA. Specific review criteria are contained in SRP Section 6.2.1.3 and other guidance provided in Matrix 6 of Power Uprate Review Standard RS-001.[132]

Technical Evaluation

The mass and energy release following a HELB in containment is discussed under Section 2.6.1, Primary Containment Functional Design. As discussed in that section, acceptable analysis models and conservative assumptions were used by the licensee. The mass and energy release methods are therefore acceptable.

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 Hope Creek EPU and appropriately accounts for the sources of energy identified in 10 CFR Part 50, Appendix K. Based on this, the NRC staff finds that the mass and energy release analysis meets the requirements in GDC-50 for ensuring that the analysis is conservative. Therefore, the NRC staff finds the proposed Hope Creek EPU acceptable with respect to mass and energy release for postulated LOCA.

2.6.4 Combustible Gas Control in Containment

Regulatory Evaluation

Following a LOCA, hydrogen and oxygen may accumulate inside the containment due to chemical reactions between the fuel rod cladding and steam, corrosion of aluminum and other materials, and radiolytic decomposition of water. If excessive hydrogen is generated, it may form a combustible mixture in the containment atmosphere. The NRC staff's review covered: (1) the production and accumulation of combustible gases; (2) the capability to prevent high concentrations of combustible gases in local areas; (3) the capability to monitor combustible gas concentrations; and (4) the capability to reduce combustible gas concentrations. The NRC staff's review primarily focused on any impact that the proposed Hope Creek EPU may have on hydrogen release assumptions, and how increases in hydrogen release are mitigated. The NRC's acceptance criteria for combustible gas control in containment are based on: (1) 10 CFR 50.44, insofar as it requires that plants be provided with the capability for controlling combustible gas concentrations in the containment atmosphere; (2) GDC-5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions; (3) GDC-41, insofar as it requires that systems be provided to control the concentration of hydrogen or oxygen that may be released into the reactor containment following postulated accidents to ensure that containment integrity is maintained; (4) GDC-42, insofar as it requires that systems required by GDC-41 be designed to permit appropriate periodic inspection; and (5) GDC-43, insofar as it requires that systems required by GDC-41 be designed to permit appropriate periodic testing. Specific review criteria are contained in SRP Section 6.2.5 and other guidance provided in Matrix 6 of Power Uprate Review Standard RS-001.[133]

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[132] ADAMS Accession No. ML033640024
[133] ADAMS Accession No. ML033640024

Technical Evaluation

The NRC revised the requirements of 10 CFR 50.44, combustible gas control for nuclear power reactors. This revision retains the existing requirement that Mark I containments such as Hope Creek's be inerted. The final rule removes the existing definition of a design basis LOCA hydrogen release and eliminates the requirements for hydrogen control systems to mitigate such a release. Accordingly, Hope Creek License Amendment 160[134] eliminated the requirements for hydrogen recombiners and hydrogen and oxygen monitors. The staff issued this license amendment by letter dated August 9, 2005.

Conclusion

The NRC staff has reviewed the licensee's assessment related to combustible gas control and concludes that the plant will continue to have sufficient control capabilities that are consistent with the requirements in 10 CFR 50.44 and GDCs 5, 41, 42, and 43 as discussed above. Therefore, the NRC staff finds the proposed Hope Creek 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 Hope Creek EPU on the analyses of the available net positive suction head (NPSH) to the containment heat removal system pumps; and (2) the analyses of the heat removal capabilities of the spray water system and the fan cooler heat exchangers. The NRC's acceptance criteria for containment heat removal are based on GDC-38, insofar as it requires that 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. Regulatory Guide 1.1, "Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps," (December 1970), specifies that emergency core cooling and containment heat removal systems should be designed so that adequate available NPSH is provided to system pumps assuming the maximum expected temperatures of pumped fluids and no increase in containment pressure from that present prior to postulated loss of coolant accidents. Specific review criteria are contained in SRP Section 6.2.2, as supplemented by Draft Guide (DG) 1107 and other guidance provided in Matrix 6 of Power Uprate Review Standard RS-001.

Technical Evaluation

The licensee's analyses discussed in Section 4.1.2 of the PUSAR[135] demonstrates that the requirements of GDC 38 are satisfied at EPU operating conditions in that containment pressure and temperature following a design basis LOCA are rapidly reduced consistent with the functioning of other systems.

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[134] ADAMS Accession No. ML050410361

[135] Attachment 4 to PSEG letter (LR-N06-0286) to NRC dated September 18, 2006, "Request for License Amendment Extended Power Uprate, Hope Creek Generating Station, Facility Operating License NPF-57, Docket No. 50-354" ADAMS Accession No. ML062680451

The licensee states that the NPSH requirements for the RHR and CS pumps were analyzed assuming zero psig containment pressure, as specified by Regulatory Guide 1.1. The following table gives the peak suppression pool temperatures for the postulated accidents considered in determining that adequate NPSH margin exists.

Event	Peak Suppression Pool Temperature (°F)	Evaluation Power Level (MWt)
Loss-of-Coolant Accident	212.3	3840 x 1.02 = 3916.8
Limiting ATWS (Pressure Regulator Failed open)	199.0	3952
Station Blackout	198.0	3952
Appendix R Fire	205.9	3840

In determining the NPSH margin at Hope Creek EPU operating conditions, the licensee employed the existing licensing basis methods for determining suction strainer debris loading and head losses.[136] [137] These methods have previously been found acceptable by the staff and their use for EPU is acceptable since the currently approved methods are expected to remain valid for the calculated increase in the peak suppression pool temperature of 11.3°F at the Hope Creek EPU operating conditions.

The RHR heat exchangers are characterized by the heat transfer coefficient, constant parameter K which is a measure of the heat exchanger effectiveness. For the Hope Creek EPU, K is equal to 307 BTU/second -°F. This value is based on a conservative fouling assumption and conservative flow rates on both the shell and tube sides of the heat exchanger.

In response to an NRC Staff RAI,[138] the licensee states that the RHR heat exchangers at Hope Creek contain relatively clean water in both the heat exchanger shell (RHR) and tubes (Safety Auxiliary Cooling Water System (SACS)). As such, these heat exchangers are not susceptible to fouling, silting, grassing, or related degradation mechanisms as would be the case with raw water systems. Since these heat exchangers contain demineralized water, the K-value is assured if the required flow rates (RHR and SACS) are periodically confirmed. These flow rates are confirmed every 18 months by plant surveillance procedures.

The NRC staff requested that the licensee verify that all input parameters not affected by the increase in power remained the same as those in previous calculations. The licensee provided a comparison of important parameters used in the Hope Creek containment safety analyses.[139] The licensee has credited heat sinks in long-term LOCA and LOOP analyses which is a change from past analysis. The additional heat sinks modeled include the drywell metal shell, the vent system metal, and the torus metal shell. Both the submerged portion of the torus shell in

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[136] Utility Resolution Guide for ECCS Suction Strainer Blockage, Volumes 1-4, BWR owners' Group, NEDO-32686-A, October 1998

[137] G. Ziegler, et al., Parametric Study of the Potential for BWR ECCS Strainer Blockage Due to LOCA Generated Debris, Final Report, NUREG/CR 6224, October 1995

[138] PSEG letter (LR-N07-0069) to NRC dated March 30, 2007, "Response to Request for Additional Information Request for License Amendment - Extended Power Uprate" ADAMS Accession No. ML071010243

[139] GE Licensing Topical Report (LTR), NEDC-33173P Revision 1, "Applicability of GE Methods to Expanded Operating Domains," February 10, 2006 ADAMS Accession No. ML060450677

contact with the suppression pool water and the torus shell portion in contact with the airspace are modeled. Heat transfer from the torus to the RB is conservatively ignored.

The licensee states that inclusion of the heat sinks results in an approximate 2 °F reduction in suppression pool temperature. This is consistent with other BWR calculations and is acceptable.

Conclusion

The NRC staff has reviewed the containment heat removal systems assessment provided by the licensee and concludes that the licensee has adequately addressed the effects of the proposed Hope Creek 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 acceptable low levels. Therefore, the NRC staff finds the proposed Hope Creek EPU acceptable with respect to containment heat removal systems.

2.6.6 Secondary Containment Functional Design

Regulatory Evaluation

The secondary containment structure and supporting ventilation and isolation systems house the refueling and reactor servicing equipment, new and spent fuel storage facilities, and other reactor auxiliary and service equipment. The primary objective of the secondary containment structure is to minimize ground level release of radioactive materials and to filter radioactive material that may leak from the primary containment following an accident. The secondary containment ventilation systems maintain a negative pressure within the secondary containment boundary to process this leakage. The NRC staff's review covered: (1) analyses of the pressure and temperature response of the secondary containment following a DBA at the proposed Hope Creek EPU operating conditions; (2) analyses of the capability of the isolation and ventilation filtration system to establish a negative secondary containment pressure in a prescribed time; and (3) analyses of the effects that the EPU may have on the 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. Specific review criteria are contained in SRP Section 6.2.3 and other guidance provided in Matrix 6 of Power Uprate Review Standard RS-001.[140]

Technical Evaluation

The staff finds the licensee's justification for secondary containment operability at the Hope Creek EPU operating conditions to be acceptable. The Filtration, Recirculation, and Ventilation system (FRVS) is designed to drawdown and maintain the secondary containment at a negative

[140] ADAMS Accession No. ML033640024

pressure and to filter the exhaust air for removal of fission products potentially present during abnormal conditions. By limiting the release of airborne particulate and halogens, the FRVS limits off-site dose following a postulated LOCA. Hope Creek TS 4.6.5.1.c.1 requires the secondary containment drawdown time to be within 375 seconds. In a letter dated March 30, 2007 (Reference 18), the licensee stated that the calculated post-Hope Creek EPU drawdown time is 238 seconds compared to the previous 221 seconds. The increase in the drawdown time is attributed to increased RB temperatures that occur within the first 375 seconds following a DBA LOCA. The NRC staff finds this acceptable, since the increase in drawdown time is marginal and stays well within the TS required limit. The PUSAR also states that the capability of the FRVS to maintain the secondary containment at the required negative pressure **[[**

]]. The PUSAR also states that the results of the AST evaluation, applicable to Hope Creek, show that the maximum charcoal loading, based on only 50 pounds of charcoal for adsorbent train, is approximately 0.26 mg of total iodine per gram of charcoal, well below the 2.5 mg/gm maximum value in Regulatory Guide 1.52. The NRC staff finds this acceptable. The maximum component temperature is approximately 168 °F with normal flow conditions and, under conditions of a failed fan, charcoal temperature is maintained below the 625 °F charcoal ignition temperature with water deluge. The NRC staff also finds this acceptable.

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 NRC staff concludes that the licensee has adequately accounted for the increase of mass and energy that would result from the proposed Hope Creek 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 Hope Creek EPU. Based on this, the NRC staff also concludes that the secondary containment and associated systems will continue to meet the requirements of GDCs 4 and 16. Therefore, the NRC staff finds the EPU acceptable with respect to secondary containment functional design.

2.6.7 Additional Review Areas (Containment Review Considerations)

Hardened Vent

Regulatory Evaluation

GL 89-16, "Installation of Hardened Wetwell Vent,"[141] discussed the advantages of installing a hardened containment (wetwell) vent and requested information from licensees on installation of such a vent. This was a result of the NRC BWR Mark I Containment Performance Improvement Program. This is a beyond-design basis issue. The licensee installed such a vent on Hope Creek.

[141] NRC Generic Letter 89-16, "Installation of Hardened Wetwell Vent," September 1, 1989. ADAMS Accession No. ML031140220

Technical Evaluation

The hardened vent design criterion is intended to maintain containment design pressure following a loss of DHR. The licensee states that the Hope Creek hardened vent is designed to accommodate decay heat input equivalent to one percent of the CLTP. This corresponds to 0.83 percent heat removal at 105 percent of EPU operating conditions (4031 MWt). The license has shown that the decay heat level reaches 0.83 percent prior to the wetwell pressure exceeding the design pressure discussed in Section 4.1.5 of the PUSAR.[142] Therefore, the design is adequate for Hope Creek EPU operating conditions.

Conclusion

The existing Hope Creek hardened wetwell vent meets the intent of GL 89-16 at extended power conditions.

Containment Isolation

Regulatory Evaluation

The NRC's acceptance criteria for containment isolation are based on GDC 50, which requires that the containment structure, including penetrations, shall be designed with sufficient margin to withstand a LOCA without exceeding the design basis leakage rate. GL 96-06, "Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions," provides specific guidance with respect to potential over pressurize piping between closed isolation valves.

Technical Evaluation

The licensee stated that the system designs for containment isolation and the capabilities of isolation actuation devices to perform under normal and post-accident conditions were reviewed for the Hope Creek EPU post-accident conditions and the Hope Creek response to GL 96-06 remains valid. On this basis, the staff finds the licensee's compliance with the guidance of GL 96-06 to be acceptable.

Conclusion

Based on the above, the Hope Creek containment isolation capabilities are not adversely affected by the EPU and continue to meet the requirements of GDC 50 and the guidance of GL 96-06.

[142] Attachment 4 to PSEG letter (LR-N06-0286) to NRC dated September 18, 2006, "Request for License Amendment Extended Power Uprate, Hope Creek Generating Station, Facility Operating License NPF-57, Docket No. 50-354" ADAMS Accession No. ML062680451

2.7 Habitability, Filtration, and Ventilation

2.7.1 Control Room Habitability System

Regulatory Evaluation

The NRC staff reviewed the control room habitability system and control building layout and structures to ensure that plant operators are adequately protected from the effects of accidental releases of toxic and radioactive gases. A further objective of the NRC staff's review was to ensure that the control room can be maintained as the backup center from which technical support center personnel can safely operate in the case of an accident. The NRC staff's review focused on the effects of the proposed Hope Creek 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 and 10 CFR50.67, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem total effective dose equivalent (TEDE). Specific review criteria are contained in SRP Section 6.4 and other guidance provided in Matrix 7 of Power Uprate Review Standard RS-001.

Technical Evaluation

For control room habitability, the NRC staff reviewed the control room ventilation system and control building layout and structures, as described in the Hope Creek UFSAR[143] and in Section 4.4 of the PUSAR,[144] regarding the control room habitability aspect of the CPPU. The objective of the NRC staff's review is to assure that plant operators are adequately protected against the effects of accidental release of toxic and radioactive gases. As stated in the licensee's EPU application,[145] the licensee performed an alternate source term (AST) analysis for the five DBAs that could potentially result in significant control room and offsite doses. License Amendment No. 134[146] for Hope Creek previously approved changes to the TSs based on full implementation of an AST pursuant to 10 CFR 50.67 using the guidance provided in RG 1.183. The five accidents included LOCA, MSL break accident, the fuel handling accident (FHA), the control rod drop accident (CRDA), and the instrument line break accident. The licensee stated that:

> "despite the increase in iodine core inventory as a result of EPU operating conditions, the iodine loading on the Control Room Emergency Filtration (CREF) charcoal filters remains a small fraction of the allowable limit of 2.5 milligram (mg) of total iodine per gram of activated carbon, as required by RG 1.52. The results of the control room habitability analysis indicate that the charcoal beds provide adequate radiation protection to the control room operators during DBAs including a LOCA with the assumed control

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[143] Hope Creek Generating Station Updated Final Safety Analysis Report, Revision 14, dated July 26, 2005. ADAMS Accession No. ML052220616

[144] Attachment 4 to PSEG letter (LR-N06-0286) to NRC dated September 18, 2006, "Request for License Amendment Extended Power Uprate, Hope Creek Generating Station, Facility Operating License NPF-57, Docket No. 50-354" ADAMS Accession No. ML062680451

[145] Attachment 1, Section 4.3 page 14-15, to PSEG letter (LR-N06-0286) to NRC dated September 18, 2006, "Request for License Amendment Extended Power Uprate Hope Creek Generating Station Facility Operating License NPF-57 Docket No. 50-354" ADAMS Accession No. ML062680451

[146] ADAMS Accession No. ML012600176

room unfiltered inleakage of 350 cubic feet per minute (cfm). The actual measured control room unfiltered inleakage is less the 200 cfm."

Based on the NRC staff review of the control room ventilation system and control building layout and structures, regarding the control room habitability, the NRC staff finds the licensee's assessment is acceptable.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the effects of the proposed Hope Creek EPU on the ability of the control room habitability system to protect plant operators against the effects of accidental releases of toxic and radioactive gases. The NRC staff concludes that the licensee has adequately accounted for the increase of toxic and radioactive gases that would result from the proposed Hope Creek EPU. The NRC staff further concludes that the control room habitability system will continue to provide the required protection following implementation of the proposed Hope Creek EPU. Based on this, the NRC staff concludes that the control room habitability system will continue to meet the requirements of GDCs 4, 19, and 10 CFR 50.67. Therefore, the NRC staff finds the proposed Hope Creek EPU acceptable with respect to the control room habitability requirements.

2.7.2 Engineered Safety Feature Atmosphere Cleanup

Regulatory Evaluation

Engineered Safety Feature (ESF) atmosphere cleanup systems are designed for fission product removal in post-accident environments. These systems generally include primary systems (e.g., in-containment recirculation) and secondary systems (e.g., SGTSs and emergency or post-accident 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 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 of 5 rem whole body, or its equivalent, to any part of the body, for the duration of the accident; (2) GDC-41, insofar as it requires that systems to control fission products released into the reactor containment be provided to reduce the concentration and quality of fission products released to the environment following postulated accidents; (3) GDC-61, insofar as it requires that systems that may contain radioactivity be designed to assure adequate safety under normal and postulated accident conditions; and (4) GDC-64, insofar as it requires that means 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. Specific review criteria are contained in SRP Section 6.5.1 and other guidance provided in Matrix 7 of Power Uprate Review Standard RS-001.[147]

[147] ADAMS Accession No. ML033640024

Technical Evaluation

The function of the atmospheric cleanup system is to mitigate the consequences of postulated accidents by removing from the atmosphere radioactive material that may be released in the event of an accident. ESF atmosphere cleanup systems should be designed so that they can operate after a DBA and can retain radioactive material after a DBA. The system should have provisions to filter air, remove moisture and meet the Regulatory Guide 1.52 guidance for charcoal adsorption.

The ESF atmospheric cleanup system at Hope Creek is the Filtration, Recirculation, and Ventilation system (FRVS), also referred to as the SGTS in the GE CLTR. As discussed in Section 4.5 of the PUSAR,[148] the acceptability of the FRVS at Hope Creek was determined by reviewing the plant-specific data at EPU operating conditions against the criteria stated in Section 4.5 of the PUSAR. The FRVS is acceptable for EPU operating conditions if the FRVS inlet temperature is below 175 °F. In a letter to the NRC dated March 30, 2007,[149] the licensee noted that post LOCA temperatures in all areas of the RB (secondary containment) under EPU operating conditions are predicted to be below 131°F, and therefore, the Hope Creek FRVS system is acceptable for EPU.

In addition, the FRVS is designed to drawdown and maintain the secondary containment at a negative pressure and to filter the exhaust air for removal of fission products potentially present during abnormal conditions. By limiting the release of airborne particulate and halogens, the FRVS limits off-site dose following a postulated LOCA. Hope Creek TS 4.6.5.1.c.1 requires the secondary containment drawdown time to be within 375 seconds. In the letter dated March 30, 2007, the licensee stated that the calculated EPU drawdown time is 238 seconds compared to the previous 221 seconds. The increase in the drawdown time is attributed to increased RB temperatures that occur within the first 375 seconds following a DBA LOCA. The NRC staff finds this acceptable, since the increase in drawdown time is marginal and stays well within the TS required limit. The PUSAR also states that the **[[**

]]. The NRC staff finds this acceptable. The maximum component temperature is approximately 168 °F with normal flow conditions and, under conditions of a failed fan, charcoal temperature is maintained below the 625 °F charcoal ignition temperature with water deluge. The NRC staff also finds this acceptable.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed Hope Creek EPU on the ESF atmosphere cleanup systems. The NRC staff concludes that the licensee has adequately accounted for the increase of fission products and changes in expected

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[149]ADAMS Accession No. ML071010243

environmental conditions that would result from the proposed Hope Creek EPU operating conditions. The NRC staff further concludes that the ESF atmosphere cleanup systems will continue to provide adequate fission product removal in post-accident environments following implementation of the proposed Hope Creek EPU. Based on this, the NRC staff concludes that the ESF atmosphere cleanup systems will continue to meet the requirements of GDCs 19, 41, 61, and 64; and 10 CFR 50.67. Therefore, the NRC staff finds the proposed Hope Creek 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 Hope Creek EPU will have on the functional performance of safety-related portions of the system. The review included the effects of radiation, combustion, and other toxic products, and the expected environmental conditions in areas served by the CRAVS. The NRC's acceptance criteria for the CRAVS are based on: (1) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (2) GDC-19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident; and (3) GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents. Specific review criteria are contained in SRP Section 9.4.1 and other guidance provided in Matrix 7 of Power Uprate Review Standard RS-001.[150]

Technical Evaluation

As indicated above, the function of the CRAVS is to provide a controlled environment for the comfort and safety of control room personnel and to assure the operability of control room components during normal operation, anticipated operational transient, and DBA conditions.

The NRC staff reviews the CRAVS from the air intake to the point of discharge where the system connects to the gaseous cleanup and treatment system or station vents to assure conformance with the requirements of GDCs 4, 19, and 60; and 10 CFR 50.67. The review includes components such as air intakes, ducts, air conditioning units, filters, blowers, isolation dampers or valves, and exhaust fans. The review of the CRAVS covers the control room, control building, cable spreading room, electrical equipment room, battery room, control area heating, ventilating and air conditioning (HVAC) equipment room, and diesel area HVAC equipment room. In the September 18, 2006, Hope Creek EPU application,[151] the licensee stated that:

> "with the exception of rescaling of some instrumentation, the Hope Creek EPU does not require any changes to the [main control room] MCR. Heat sources in the MCR are due

[150] ADAMS Accession No. ML033640024
[151] ADAMS Accession No. ML062680451

> to equipment, ambient outside air temperature, and personnel, and do not change with [respect to] the EPU. There are no changes to the MCR envelope and there are no significant changes to the temperatures in the adjacent walls and ceilings. Accordingly, there is no change in the heating and cooling loads, required ventilation flow, or the MCR capability to establish isolation and maintain positive pressure with respect to outside boundaries."

In a letter dated March 30, 2007,[152] the licensee further stated that "temperature changes in the Control Building are negligible. The Hope Creek EPU does not add any electrical or electronic equipment. The Hope Creek EPU may add some amperage for control and indication signals but the resulting changes in temperatures are considered negligible. The rooms that are adjacent to the control room contain ventilation equipment or electrical or electronic equipment. These rooms are not impacted by the EPU and therefore there are no temperature changes in these rooms that can impact main control room temperatures." The staff finds this acceptable.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed Hope Creek 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. As indicated in section 2.7.1 above, 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 Hope Creek EPU, and associated changes to parameters affecting environmental conditions for control room personnel and equipment. Accordingly, the NRC staff concludes that the CRAVS will continue to provide an acceptable control room environment for safe operation of the plant following implementation of the proposed Hope Creek EPU. The NRC staff also concludes that the system will continue to suitably control the release of gaseous radioactive effluents to the environment. Based on this, the NRC staff concludes that the CRAVS will continue to meet the requirements of GDCs 4, 19, and 60. Therefore, the NRC staff finds the proposed Hope Creek 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 Hope Creek EPU on the functional performance of the safety-related portions of the system. The NRC's acceptance criteria for the SFPAVS are based on: (1) GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents; and (2) GDC-61, insofar as it requires that systems which contain radioactivity be designed with appropriate confinement and containment. Specific review criteria are contained in SRP Section 9.4.2 and other guidance provided in Matrix 7 of Power Uprate Review Standard RS-001.[153]

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[152] ADAMS Accession No. ML071010243
[153] ADAMS Accession No. ML033640024

Technical Evaluation

The function of the SFPAVS is to maintain ventilation in the SFP equipment area, to permit personnel access, and to control air borne radioactivity in the area during normal operation, anticipated operational transients, and following postulated FHAs.

The staff reviews the SFPAVS from air intake to the point of discharge where the system connects to the gaseous cleanup and treatment system or the station vents to assure conformance with the requirements of GDCs 60 and 61. The review includes components such as air intakes, ducts, air conditioning units, filters, blowers, isolation dampers, and exhaust fans. The review of the SFPAVS covers all areas containing or adjacent to the SFP, including the spent fuel cooling pump room.

In the September 18, 2006, Hope Creek EPU application,[154] the licensee stated that the SFP area is within the RB and within the secondary containment ventilation envelope that it is served by the Hope Creek FRVS. The licensee further stated that, "EPU does not adversely affect the normal or accident SFP heat loads to the RB ventilation system." In the letter dated March 30, 2007,[155] the licensee also stated that, "no changes in refueling floor HVAC [ventilation] loading result from EPU because the existing licensing basis SFP temperatures are maintained by the FPC and Cleanup System. Hope Creek can maintain SFP pool temperature limits for offloads below the current licensing limits of 135 °F (batch) and 150 °F (full core) with increased EPU decay heat loads." The staff finds this acceptable.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the EPU on the SFPAVS. The NRC staff concludes that the licensee has adequately accounted for the effects of the 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 this, the NRC staff concludes that the SFPAVS will continue to meet the requirements of GDCs 60 and 61. Therefore, the NRC staff finds the proposed Hope Creek EPU acceptable with respect to the SFPAVS.

2.7.5 Auxiliary and Radwaste Area and Turbine Areas Ventilation Systems

Regulatory Evaluation

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

[154] ADAMS Accession No. ML062680451
[155] ADAMS Accession No. ML071010243

Specific review criteria are contained in SRP Sections 9.4.3 and 9.4.4 and other guidance provided in Matrix 7 of Power Uprate Review Standard RS-001.[156]

Technical Evaluation

The staff reviews the ARAVS from air intake to the point of discharge where the system connects to the gaseous cleanup and treatment system or station vents to assure conformance with the requirements of GDC 60. The review includes components such as air intakes, ducts, air conditioning units, blowers, isolation dampers, and roof exhaust fans. The review of the ARAVS covers the radwaste areas and controlled access nonradioactive areas and their relationship to safety-related areas in the auxiliary building. In the September 18, 2006, Hope Creek EPU application,[157] the licensee stated that,

]]. Thus, the recombiner and condenser, as well as downstream components, are designed to handle an average increase in thermal power of as much as 57 percent relative to OLTP operating conditions, without exceeding the design basis temperatures, flow rates, or heat loads." The licensee further stated in the same letter that, "operation at Hope Creek EPU conditions does result in a small increase in the volume of liquid and solid radwaste, but these do not affect the process temperature or electrical load changes. The Hope Creek EPU does increase the amount of hydrogen gas production by radiolysis, but the amount remains within the original design for the off-gas system recombiners. Therefore, the ventilation in the radwaste handling areas is not adversely affected by the Hope Creek EPU." In addition, the radwaste area ventilation system has no safety-related function and its failure does not compromise any safety-related system or component, or prevent safe shutdown. The staff finds this acceptable.

The NRC staff reviewed the TAVS from air intake to the point of discharge to assure conformance with the requirements of GDC 60. The review included components such as air intakes, ducts, cooling units, blowers, isolation dampers, roof exhaust fans. The review of the TAVS includes systems contained in the turbine building and their relationship, if any, to safety-related equipment areas.

With respect to the turbine area ventilation system (TAVS), the licensee stated that the Hope Creek EPU results in slightly higher process temperatures and small increases in the heat load due to higher electrical currents in some motors and cables. For the Hope Creek EPU operating condition, it was determined that the following areas serviced by the turbine building HVAC would experience temperature increases as indicated.

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[156] ADAMS Accession No. ML033640024
[157] ADAMS Accession No. ML062680451

Area	Ambient Temperature Increase @ EPU (°F)
Moisture Separator Rooms	1.1
Feed Water Pump Area	2.0
Feed Water Heater #6 Area	2.0
Lower FWH Areas (#3, 4, 5)	3.5
Condensate Pump Rooms	Negligible
Steam Tunnel Area	0.5

Conclusion

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

2.7.6 Engineered Safety Feature Ventilation System

Regulatory Evaluation

The function of the engineered safety feature ventilation system (ESFVS) is to provide a suitable and controlled environment for ESF components following certain anticipated transients and DBAs. The NRC staff's review for the ESFVS focused on the effects of the proposed Hope Creek EPU operating conditions on the functional performance of the safety-related portions of the system. The NRC staff's review also covered: (1) the ability of the ESF equipment in the areas being serviced by the ventilation system to function under degraded ESFVS performance; (2) the capability of the ESFVS to circulate sufficient air to prevent accumulation of flammable or explosive gas or fuel-vapor mixtures from components (e.g., storage batteries and stored fuel); and (3) the capability of the ESFVS to control airborne particulate material (dust) accumulation. The NRC's acceptance criteria for the ESFVS are based on: (1) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (2) GDC-17, insofar as it requires onsite and offsite electric power systems be provided to permit functioning of SSCs important to safety; and (3) GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents. Specific review criteria are contained in SRP Section 9.4.5 and other guidance provided in Matrix 7 of Power Uprate Review Standard RS-001.[158]

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[158] ADAMS Accession No. ML033640024

Technical Evaluation

As stated above, the function of the ESFVS is to provide a suitable and controlled environment for engineered safety feature components following certain anticipated transients and design basis accidents.

The staff reviews the ESFVS from air intake to the point of discharge to the atmosphere to assure conformance with the requirements of GDCs 4, 17, and 60. The review includes components such as air intakes, ducts, air conditioning units, flow control devices, isolation dampers, exhaust vents, and exhaust fans.

The review of the ESFVS covers all ventilation systems utilized to maintain a controlled environment in areas containing safety-related equipment. These include the intake structure pump house, EDG rooms, ECCS pump rooms, RCIC pump room, and safety auxiliaries cooling system (SACS) pump room.

In Section 6.6 of the PUSAR[159] and in a letter dated March 30, 2007,[160] the licensee stated that the design basis heat loads are based on full rated capacity of the EDG and that the EDG remains below rated capacity post-Hope Creek EPU operating conditions. The licensee also stated that there are essentially no electrical loads or process temperature changes in the design basis heat loads in this area.

In regards to the ECCS pump rooms and SACS pump room, the licensee has stated that the room temperatures were evaluated by a GOTHIC model analysis. The licensee stated that there is a small increase in the post LOCA suppression pool temperature, from the assumed peak of 212 °F to the calculated EPU operating conditions analysis temperature of 212.3 °F. The room temperature increases are less than 1°F and the impact on ECCS room coolers and equipment performance is insignificant. GOTHIC code has been determined by the NRC to be an acceptable code for use in this type of analysis. Based on an assessment of this information, the Staff finds it acceptable.

Conclusion

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

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[159] Attachment 4 of PSEG letter (LR-N06-0286) to NRC dated September 18, 2006, "Request for License Amendment Extended Power Uprate Hope Creek Generating Station Facility Operating License NPF-57 Docket No. 50-354" ADAMS Accession No. ML062680451

[160] ADAMS Accession No. ML071010243

2.8 Reactor Systems

In the operating cycle in which the Hope Creek EPU will be first implemented (Cycle 15), there will be predominantly GE14 fuel with some remaining average thrice burned SVEA-96+ fuel (8 fuel assemblies are twice burnt). The EPU safety analyses and the cycle-specific reload analyses will be performed in accordance with NRC-approved GE analytical methodologies described in the latest version of GESTAR-II.[161] The LTRs specifying the codes and methodologies used for performing the safety analyses are documented in the Hope Creek TSs. The limiting AOOs and accident analyses are reanalyzed or confirmed to be valid for every reload and the safety analyses of transients and accidents are documented in Chapter 15 of the UFSAR.[162] Limiting transient or accident analyses are generally defined as analyses of events that could potentially affect the core operating and SLs that ensure the safe operation of the plant.

In the Hope Creek EPU application,[163] the licensee referenced the GE LTR, NEDC-33173P, "Applicability of GE Methods to Expanded Operating Domains".[164] Attachment 15 of the Hope Creek EPU application contains the specific supplement to the LTR NEDC-33173P. The licensee agreed, consistent with the NRC staff SE for NEDC-33173P,[165] to take penalties on certain fuel limit parameters for Hope Creek EPU operation. The results of the detailed NRC staff evaluation in this area are provided in Section 2.8.7 of this SE.

2.8.1 Fuel System Design

Regulatory Evaluation

The fuel system consists of arrays of fuel rods, burnable poison rods, spacer grids and springs, end plates, channel boxes, and reactivity control rods. The NRC staff reviewed the fuel system to ensure that: (1) the fuel 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 NRC staff's review covered fuel system damage mechanisms, limiting values for important parameters, and performance of the fuel system during normal operation, AOOs, and postulated accidents. The NRC's acceptance criteria are based on: (1) 10 CFR 50.46, insofar as it establishes standards for the calculation of ECCS performance and acceptance criteria for that calculated performance; (2) GDC-10, insofar as it requires that the reactor core be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs; (3) GDC-27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; and (4) GDC-35, insofar as it requires that a system to provide abundant emergency core cooling be provided to transfer heat from the

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[161] GE Nuclear Energy, "Generic Electric Standard Application for Reactor Fuels, "NEDE-24011-P-A and NEDE-24011-P-A-US," (latest approved version)(Known as GESTAR-II) ADAMS Accession No. ML011230175
[162] ADAMS Accession No. ML052220616
[163] ADAMS Accession No. ML062680451
[164] ADAMS Accession No. ML060450677
[165] ADAMS Accession No ML073340231

reactor core following any LOCA. Specific review criteria are contained in SRP Section 4.2 and other guidance provided in Matrix 8 of Power Uprate Review Standard RS-001.[166]

Technical Evaluation

The fuel system design at Hope Creek is described in Section 4.2 of the UFSAR.[167] The licensee plans to implement the Hope Creek EPU during the 15th operating cycle (Cycle 15) in which there will be a mixed reactor core combination of GE14 and SVEA-96+ fuel. The core thermal-hydraulic design and fuel performance characteristics are evaluated for each reload fuel cycle. The following sections address the effect of the Hope Creek EPU on fuel design performance and thermal limits.

Fuel Design and Operation

In the PUSAR,[168] the licensee states that the EPU increases the average power density proportional to the power increase and has some effects on operating flexibility, reactivity characteristics and energy requirements. The peak bundle power will increase from **[[** .**]]** The power distribution in the core is changed at CPPU conditions to achieve increased core power, while the Safety Limit Minimum Critical Power Ratio (SLMCPR), Linear Heat Generation Rate (LHGR), and Maximum Average Planar Linear Heat Generation Rate (MAPLHGR) in any individual fuel bundle will be within operating limits as defined in the core operating limits report (COLR).

In the first Hope Creek EPU core (Cycle 15), there will be predominantly GE14 fuel with some remaining average thrice burned legacy fuel (SVEA-96+). In response to the NRC staff's RAI, by letter dated March 13, 2007,[169] the licensee stated that the SVEA-96+ fuel operating in the Cycle 15 core will be high exposure, low reactivity fuel in its fourth or fifth operating cycle, and therefore, only GE14 fuel bundles are expected to be limiting in regards to the SLMCPR evaluation. The SVEA-96+ peak bundle power is significantly lower than that of the limiting GE14 fuel. It was stated that based on this lower power, the results of the Cycle 15 EPU core design demonstrate that the GE14 fuel is limiting for critical power ratio (CPR) and MAPLHGR (which protects peak clad temperatures (PCTs)) for the entire operating cycle. The GE14 fuel is also limiting for LHGR for the majority of the operating cycle, except for a brief exposure interval near the end of the cycle. This exception occurs during a period when the GE14 LHGR is relatively low, and significant margin exists to the LHGR limit. The licensee further stated that the actual Cycle 15 licensing basis core design is not yet complete, however, it is expected that the thermal limit performance results will be similar to what has been described above, with the GE14 fuel the limiting fuel type with respect to thermal limits. This will be confirmed by the licensee by performing cycle-specific analyses, and the results will be documented in the Supplemental Reload Licensing Report (SRLR) for the cycle prior to startup. The staff finds this approach acceptable.

The licensee states that **[[** **]]** The

[166] ADAMS Accession No. ML033640024
[167] ADAMS Accession No. ML052220616
[168] Attachment 4 to PSEG letter (LR-N06-0286) to NRC dated September 18, 2006, "Request for License Amendment Extended Power Uprate, Hope Creek Generating Station, Facility Operating License NPF-57, Docket No. 50-354" ADAMS Accession No. ML062680451
[169] ADAMS Accession No. ML070790508

fuel design limits are established for all new fuel product line designs as a part of the fuel introduction and reload analyses. The NRC staff evaluated several areas related to application of GE methods used for the Hope Creek EPU and mixed-core operation. Consistent with the non-public, NRC staff SER[170] for NEDC-33173P,[171] the licensee agreed to take fuel limit penalties on certain parameters for EPU operation.

Because the licensee will continue to use approved analytical methods, apply NRC staff requested interim fuel methods penalties to account for additional uncertainties, and will continue to ensure that the results of those analyses remain within currently acceptable limits, the NRC staff finds the proposed EPU acceptable with respect to fuel design and operation.

Thermal Limits Assessment

The NRC's acceptance criteria for EPU operations 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 SLs are not exceeded for a range of postulated events (transients and accidents).

The SLMCPR ensures that 99.9 percent of the fuel rods are protected from boiling transition during an AOO. The operating limit minimum critical power ratio (OLMCPR) provides margin during steady state plant operation to assure that the SLMCPR will not be exceeded as result of an AOO. NRC staff experience with several power uprates has shown that the change in OLMCPR resulting from a CPPU is small. This issue can be generically dispositioned, and there is no need to perform evaluations with a representative core design parameters. When the core design is complete, the OLMCPR will be determined with the cycle-specific core design parameters. Because the licensee will use previous NRC-approved methods to evaluate these parameters, this is acceptable to the staff. As required by the NRC-approved EPU guidelines[172] the licensee will perform plant-cycle-specific reload analysis to demonstrate that the SLMCPR and OLMCPR are appropriate for establishing the EPU thermal limits.

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. For every new fuel type, the fuel vendor performs a LOCA analyses to confirm compliance with the NRC LOCA acceptance criteria, and for every reload, licensees confirm that the MAPLHGR operating limit for each reload fuel bundle design remains applicable. The licensee performed a LOCA evaluation, based on a power uprate representative equilibrium cycle core design while operating at the EPU power level, and is evaluated in Section 2.8.5.6.2 of this SE.

In general, the licensee must ensure that plant operation is in compliance with the cycle-specific fuel thermal limits (SLMCPR, OLMCPR, MAPLHGR, and maximum LHGR) and specify the thermal limits in a cycle-specific COLR as required by the Hope Creek TSs. In addition, while the Hope Creek EPU operation may result in an increase in fuel burn up, the licensee can not

[170] ADAMS Accession No. ML073340231
[171] ADAMS Accession No. ML070390406
[172] NRC Staff Review of GE Nuclear Energy Licensing Topical Report, NEDC-33004P, Revision 3, "Constant Pressure Power Uprate," dated March 31, 2003 (ML031190318); Appendix K of General Electric Licensing Topical Report (LTR) NEDC-32424P-A (February 1999), "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," (ELTR1); and Section 4.8 of Supplement 1 of GE Licensing Topical Report, NEDC-32523P-A (February 2000), "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate" (ELTR2) (ML003712826)

exceed the NRC approved burn up limits. In accordance with the Hope Creek TS, cycle-specific analyses are performed using NRC reviewed and approved methodologies. The NRC staff finds that the licensee has appropriately considered the potential effects of EPU operation on the fuel design limits, and the generic thermal limits assessment show that Hope Creek can operate at EPU conditions with the required fuel design limits during steady state operation, AOOs, and accident conditions.

The TS required SLMCPR fuel limit ensures that the fuel does not experience transition boiling as a result of normal operation and AOOs at EPU conditions. Compliance with 10 CFR 50.46, as discussed further in Section 2.8.5.6.2 of this SE, ensures that in the event of a DBA LOCA fuel system damage will not prevent control rod insertion, and that core coolability would be maintained.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed Hope Creek EPU on the fuel system design, the fuel assemblies, control systems, and reactor core. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the fuel systems, consistent with the staff's understanding described in the NRC-approved EPU guidelines previously mentioned, and demonstrated that: (1) the fuel will not be damaged as a result of normal Hope Creek EPU operation and during AOOs; (2) the fuel damage during a DBA LOCA will never be so severe as to prevent control rod insertion when it is required; (3) the number of fuel rod failures will not be underestimated for postulated accidents; and (4) coolability will also be maintained. In addition, the licensee will perform plant-specific reload analyses to confirm that SAFDLS and RCPB pressure limits will not be exceeded during the planned operating fuel cycles at EPU conditions. Based on this, the NRC staff concludes that the fuel system and associated analyses will continue to meet the requirements of 10 CFR 50.46, GDC-10, GDC-27, and GDC-35 following implementation of the proposed Hope Creek EPU. Therefore, the NRC staff finds the proposed Hope Creek EPU acceptable with respect to the fuel system design.

2.8.2 Nuclear Design

Regulatory Evaluation

The NRC staff reviewed the nuclear design of the fuel assemblies, control systems, and reactor core to ensure that fuel design limits will not be exceeded during normal operation and anticipated operational transients, and that the effects of postulated reactivity accidents will not cause significant damage to the RCPB or impair the capability to cool the core. The NRC staff's review covered core power distribution, reactivity coefficients, reactivity control requirements and control provisions, control rod patterns and reactivity worths, criticality, burn up, and vessel irradiation. The NRC's acceptance criteria are based on: (1) GDC-10, insofar as it requires that the reactor core be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs; (2) GDC-11, insofar as it requires that the reactor core be designed so that the net effect of the prompt inherent nuclear feedback characteristics tends to compensate for a rapid increase in reactivity; (3) GDC-12, insofar as it requires that the reactor core be designed to assure that power oscillations, which can result in conditions exceeding SAFDLs, are not possible or can be reliably and readily detected and suppressed; (4) GDC-13, insofar as it requires that instrumentation and controls be provided to monitor variables and systems affecting the fission process over anticipated ranges for normal operation, AOOs and accident conditions, and to maintain the variables and systems within prescribed operating ranges; (5) GDC-20, insofar as it requires that the protection system be designed to initiate the reactivity control systems automatically to assure that acceptable fuel design limits are not exceeded as a result of AOOs and to automatically initiate operation of systems and components important to safety under accident conditions; (6) GDC-25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems; (7) GDC-26, insofar as it requires that two independent reactivity control systems be provided, with both systems capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes; (8) GDC-27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; and (9) GDC-28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core. Specific review criteria are contained in SRP Section 4.3 and other guidance provided in Matrix 8 of Power Uprate Review Standard RS-001.[173]

Technical Evaluation

The nuclear design of Hope Creek is described in Section 4.3 of the Hope Creek UFSAR.[174] The topics addressed by the licensee in this evaluation are:

• Hot excess reactivity

• Shutdown margin (SDM)

The higher core energy requirements of a CPPU may affect the hot excess core reactivity and can also affect operating SDMs. The general effect of a power uprate on core reactivity, as described in Section 5.7.1 of ELTR-1,[175] is also applicable to a CPPU. Based on experience with previous plant-specific power uprate submittals, the required hot excess reactivity and SDM 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 in GESTAR-II[176] on a cycle-specific basis and are evaluated for each plant reload core, and additional hot excess reactivity and SDM analyses are not specifically required for a plant-specific EPU.

The Hope Creek EPU reload core design will ensure that the minimum SDM requirements are met for each core design and that the current design and TS cold SDM will be met. Since the licensee will continue to confirm that the TS cold shutdown requirements will be met for each reload core operation, the staff finds this acceptable, and concludes that the existing NRC's

[173] ADAMS Accession No. ML033640024
[174] ADAMS Accession No. ML052220616
[175] Appendix K of General Electric Licensing Topical Report (LTR) NEDC-32424P-A (February 1999), "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," (ELTR1) ADAMS Accession No. ML003680231
[176] GE Nuclear Energy, "Generic Electric Standard Application for Reactor Fuels, "NEDE-24011-P-A and NEDE-24011-P-A-US," (latest approved version)(Known as GESTAR-II) ADAMS Accession No. ML011230175

acceptance criteria will continue to be satisfied. The licensee, therefore, will evaluate the SDM for the uprated reload core prior to EPU implementation.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effect of the proposed EPU on the nuclear design of the fuel assemblies, control systems, and reactor core. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the nuclear design, consistent with the staff's understanding described in the NRC-approved EPU guidelines previously mentioned, and has demonstrated that the fuel design limits will not be exceeded during normal or anticipated operational transients, and that the effects of postulated reactivity accidents will not cause significant damage to the RCPB or impair the capability to cool the core. In addition, the licensee will perform plant-specific reload analyses to confirm that SAFDLS and RCPB pressure limits will not be exceeded during the planned cycle. Based on this evaluation and in coordination with the reviews of the fuel system design, thermal and hydraulic design, and transient and accident analyses, the NRC staff concludes that the nuclear design of the fuel assemblies, control systems, and reactor core will continue to meet the applicable requirements of GDCs 10, 11, 12, 13, 20, 25, 26, 27, and 28. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the nuclear design.

2.8.3 Thermal and Hydraulic Design

Regulatory Evaluation

The NRC staff reviewed the thermal and hydraulic design of the core and the RCS to confirm that the design: (1) has been accomplished using acceptable analytical methods; (2) is equivalent to or a justified extrapolation from proven designs; (3) provides acceptable margins of safety from conditions which would lead to fuel damage during normal reactor operation and AOOs; and (4) is not susceptible to thermal-hydraulic instability. The NRC's acceptance criteria are based on: (1) GDC-10, insofar as it requires that the reactor core be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs; and (2) GDC-12, insofar as it requires that the reactor core and associated coolant, control, and protection systems be designed to assure that power oscillations, which can result in conditions exceeding SAFDLs, are not possible or can reliably and readily be detected and suppressed. Specific review criteria are contained in SRP Section 4.4 and other guidance provided in Matrix 8 of Power Uprate Review Standard RS-001.[177]

Technical Evaluation

The thermal and hydraulic reactor core design is described in Section 4.4 of the Hope Creek UFSAR.[178] The evaluation for thermal hydraulic stability will be performed during the reload analysis. This is acceptable because the equilibrium cycle analysis is not necessary to demonstrate that the applicable stability solution will provide thermal-hydraulic stability protection at EPU operating conditions, and the necessary stability analysis will be performed during the reload process.

Hope Creek is currently operating under Boiling-Water Reactor Owner's Group (BWROG) Long

[177] ADAMS Accession No. ML033640024
[178] ADAMS Accession No. ML052220616

Term Stability Solution Option-III using the Oscillation Power Range Monitor (OPRM) as described in NEDO-31960-A and NEDO-31960, Supplement 1, “BWROG Long-Term Stability Solution Licensing Methodology,” and CENPD-400-P-A, Rev. 1, “Generic Topical Report for the ABB Option III Oscillation Power Range Monitor.”[179] The Hope Creek OPRM system is an ABB corporation OPRM design, which comprised of four OPRM channels that provide inputs to an associated reactor protection system (RPS) channel via eight OPRM modules. Each OPRM channel takes amplified local power range monitor (LPRM) signals from one APRM group and either another APRM group or one unassigned LPRM group. The LPRM signals are grouped together such that the resulting OPRM response provide adequate coverage of anticipated oscillation modes. Each OPRM channel consists of two OPRM modules and contains more than 30 OPRM cells, where a cell represents a combination of four LPRMs in adjacent areas of the core. Stability Long Term Solution Option III consists of hardware and software that provides for reliable, automatic detection and suppression of stability related power oscillations.

The licensing basis of the Option III methodology is the same for both the GE and ABB OPRM designs. The OPRM trips enabled for Hope Creek include the licensing basis Period Based Detection Algorithm as well as for the Growth Rate Algorithm, and Amplitude Based Algorithm defense-in-depth features. The algorithms for the Long Term Stability Option III solution are described in NEDO-32465-A, “Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications.”[180]

The OPRM amplitude setpoint calculation is comprised of three components as defined in NEDO-32465-A. The calculation for hot channel oscillation magnitude is performed using the approved GE methodology, the generic DIVOM (Δ critical power ratio (CPR)/ initial CPR versus Oscillation Magnitude) curve calculations used the earlier TRACG 02 computer code version and pre-PANAC11 computer code neutronic method.

GE has performed an evaluation comparing the use of TRACG04-PANAC11 versus TRACG02-PANAC10 in the calculation of DIVOM slopes and determined that results are essentially the same. Cycle-specific setpoint calculations are now performed to determine the OLMCPR needed to protect the SLMCPR for the various OPRM amplitude setpoints. 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 defined as the region on the power/flow map with power ≥30 percent CLTP and core flow ≤60 percent rated core flow. For CPPU, the Option III trip-enabled region is rescaled to maintain the same power/flow region boundaries (i.e., rated power ≥26.1 percent and rated core flow ≤ 60 percent for Hope Creek at EPU conditions of 115 percent CLTP).

Hope Creek uses the BWROG Interim Corrective Action (ICA) stability regions as the backup stability protection (BSP) method when the OPRM system is declared to be inoperable. These regions are confirmed on a cycle-specific basis by performing BSP calculations in accordance with the guidance provided in OG02-0119-260, “Backup Stability Protection (BSP) for inoperable Option III Solution”, dated July 17, 2002. The evaluation is given in NEDC-33179P-R1, “MELLLA Backup Stability Protection Evaluation for Hope Creek Cycle 14 at CPPU Condition,”[181] to demonstrate the stability performance of a mixed core of SVEA 96+ and GE14 fuel at CPPU condition of 115 percent of CLTP with operation in the MELLLA domain and no

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[179] ADAMS Accession No. ML072260015
[180] NEDO-32465-A, “Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications”
[181] NEDC-33179P-R1, “MELLLA Backup Stability Protection Evaluation for Hope Creek Cycle 14 at CPPU Condition,” ADAMS Accession No. ML053180379

change in the normal maximum operating pressure. The GE ODYSY code is used for the calculation of decay ratios (DRs) based on statepoint and neutronic data from PANAC11 and TGBLA06 computer codes. If the ODYSY calculations determine that the BSP regions are larger than the corresponding ICA regions, then the larger BSP regions are used for stability monitoring in the event that the OPRM system is declared inoperable.

The Hope Creek TSs rely on the BWROG ICAs as its BSP when the OPRM system is unavailable. It is acceptable that Hope Creek uses generic (step-wise) BWROG regions for their ICAs, which are verified for adequacy every reload. However, the OPRM trip setpoints and regions of ICAs should be specified in the COLR.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed Hope Creek EPU on the thermal and hydraulic design of the core and the RCS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the thermal and hydraulic design and demonstrated that the design: (1) has been accomplished using acceptable analytical methods; (2) is equivalent to or a justified extrapolation from proven designs; (3) provides acceptable margins of safety from conditions that would lead to fuel damage during normal reactor operation and AOOs; and (4) is not susceptible to thermal-hydraulic instability. Based on this, the NRC staff concludes that the thermal and hydraulic design will continue to meet the requirements of GDCs 10 and 12 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to thermal and hydraulic design.

2.8.4 Emergency Systems

2.8.4.1 Functional Design of Control Rod Drive System

Regulatory Evaluation

The NRC staff's review covered the functional performance of the CRDS to confirm that the system can affect a safe shutdown, respond within acceptable limits during AOOs, and prevent or mitigate the consequences of postulated accidents. The review also covered the CRDS cooling system to ensure that it will continue to meet its design requirements. The NRC's acceptance criteria are based on: (1) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (2) GDC-23, insofar as it requires that the protection system be designed to fail into a safe state; (3) GDC-25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems; (4) GDC-26, insofar as it requires that two independent reactivity control systems be provided, with both systems capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes; (5) GDC-27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; (6) GDC-28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core; (7) GDC-29, insofar as it requires that the protection and reactivity control systems be designed to assure an extremely high probability of accomplishing their safety functions in event of AOOs; 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. Specific review criteria are contained in SRP Section 4.6 and other guidance provided in Matrix 8 of Power Uprate Review Standard RS-001.[182]

Technical Evaluation

The Hope Creek CRDS is described in Section 4.6 of the Hope Creek UFSAR.[183] The CRDS controls gross and local changes in core reactivity by incrementally positioning individual neutron-absorbing control rods within the reactor core in response to manual control signals from the reactor manual control system (RMCS). In addition, the CRDS is required to automatically shutdown (scram) the reactor during AOOs or under plant accident conditions by rapidly inserting all withdrawn control rods into the reactor core in response to a reactor trip setpoint actuation of the RPS or ARI system. The RMCS provides the manual control rod insertion and withdrawal signal functions of the CRDS which is dependent on the differential pressure between the CRD hydraulic supply pressure control valves and the reactor vessel pressure. Each hydraulic control unit (HCU) has a scram accumulator pressurized with hydraulic charging pressure to approximately 1400-1500 psig to provide sufficient energy to fully insert a control rod at lower vessel pressures and provides for initial insertion pressure for each control rod during a scram condition at higher vessel pressures.

The CRDS was **[[ ]]** evaluated in Sections 5.6.3 and J.2.3.3 of ELTR1[184] and Section 4.4 of Supplement 1 to ELTR2.[185] The **[[ ]]** the original rated power.

In Section 2.5 of the Hope Creek PUSAR,[186] the licensee confirmed that the **[[ ]]**. The Hope Creek nominal reactor dome pressure during EPU conditions does not change; therefore, the scram time performance relative to current plant operation is the same. As a result, the current TS scram requirements are not affected and remain valid under the proposed Hope Creek EPU operating conditions.

Based on the **[[ ]]** evaluations ELTR1 and ELTR2, and the Hope Creek UFSAR section 4.6.1.2.4.1, the NRC staff finds that the performance of the Hope Creek CRD cooling and positioning or drive functions at the proposed EPU conditions will be adequate. There will be a minimum pressure of approximately **[[ ]]** maintained between the CRD hydraulic supply and the reactor vessel pressure for CRD insertion and withdrawal. The automatic operation of the CRDS flow control valves and pressure control valves maintain the required drive water and cooling water pressure and

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[182] ADAMS Accession No. ML033640024
[183] ADAMS Accession No. ML052220616
[184] Appendix K of General Electric Licensing Topical Report (LTR) NEDC-32424P-A (February 1999), "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," (ELTR1) ADAMS Accession No. ML003580231
[185] Section 4.8 of Supplement 1 of GE Licensing Topical Report, NEDC-32523P-A (February 2000), "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate" (ELTR2) ADAMS Accession No. ML003712826
[186] Attachment 4 to PSEG letter (LR-N06-0286) to NRC dated September 18, 2006, “Request for License Amendment Extended Power Uprate, Hope Creek Generating Station, Facility Operating License NPF-57, Docket No. 50-354” ADAMS Accession No. ML062680451

system flows at various reactor vessel pressure conditions. In Section 2.5.2 of the Hope Creek PUSAR, the licensee confirmed that the CRDS in service flow control valve is approximately 50 percent open at CLTP, based on plant operational data. Therefore, the flow control valve will maintain the required system flow at the proposed EPU conditions.

The NRC staff finds that the Hope Creek CRD hydraulic capability and capacity are sufficient to provide the required CRD positioning, CRD cooling and scram accumulator charging requirements at the proposed Hope Creek EPU operating conditions.

Fuel channel bow is elongation of one fuel channel face relative to the opposite fuel channel face. Fuel channel bow has been known to occur, and has been modeled in fuel licensing (thermal limits) analysis, and mitigated in core design. Previous occurrences of fuel channel bow have been known to arise from these sources: initial manufacturing, residual stress relaxation under irradiation, and differential irradiation caused by fast fluence gradients. Corrosion of the fuel channel outer surface can occur when a control blade is inserted next to the fuel channel. Corrosion can result in increased absorbed hydrogen-induced growth of the fuel channel wall closest to the control blade, which leads to channel bowing.

On March 3, 2003, General Electric Nuclear Energy (GENE) issued a 10 CFR Part 21 notification concerning a reportable condition of fuel channel bow. GENE recommended an interim penalty of 0.02 on the OLMCPR for BWR/6 plants affected by the fuel channel bow phenomenon to compensate for possible fuel channel-control blade interference and to maintain operation within acceptable limits. Since Hope Creek is a BWR/4 plant, the Hope Creek licensee did not adopt the 0.02 OLMCPR penalty. On April 30, 2003, GENE recommended an interim surveillance program for fuel channel bow monitoring for BWR/6 and BWR/4&5 C-lattice plants. The interim surveillance program was intended to permit affected licensees to detect channel-control blade friction and take compensatory actions before reaching excessive control blade friction. GENE indicated that BWR/2, 3, and 4 D-lattice plants were excluded from the interim surveillance program. Hope Creek is a BWR/4 C-lattice plant.

By letter dated July 14, 2005, GENE revised the surveillance program of channel-control blade interference. The revised surveillance program included a surveillance plan for the BWR/6 S-lattice plants and another surveillance plan for the BWR/2-5 C/D-lattice plants. Hope Creek was one of the plants that GENE recommended for implementation of the revised surveillance program. Hope Creek has not previously implemented the recommended GE surveillance program due to several factors including: 1) the SVEA fuel in operation at the time of the July 14, 2005, GE letter was not impacted by the GE channel-control blade interference issue; 2) Hope Creek was not controlling fresh GE 14 fuel and was operating with 18-month fuel cycles; and 3) the existing GE 14 fuel was not operating at the susceptible exposure values. However, the licensee stated that Hope Creek will be implementing the GE surveillance program recommendations as GE 14 fuel in the core approaches the susceptible exposure values. Hope Creek is currently following the guidance of SIL 320, Supplement 3.

The protection provided for the system against dynamic effects and missiles that might result from equipment failures is not affected by the proposed EPU. The CRD components have been evaluated for design pressures higher than the anticipated maximum pressure resulting from the power uprate. Therefore, the CRDS integrity is confirmed to be consistent with the generic description provided in ELTR2.[187]

[187] GE Licensing Topical Report, NEDC-32523P-A (February 2000), "Generic Evaluations of General Electric Boiling Water Reactor

The CRDS capability to sustain any single malfunction without causing a reactivity transient is unaffected by the proposed Hope Creek EPU. Two independent reactivity control systems (CRDS and SLCS) are still provided. The capability of either of these systems to make the core subcritical under any condition is unaffected while operating at EPU conditions. Control rod worth limits, which include considerable margin, are also unaffected.

Hope Creek installed an ARI system as part of its Redundant Reactivity Control System which is independent of the Hope Creek RPS. ARI is designed to increase the reliability of the CRDS scram function. The Hope Creek ARI provides for insertion of reactor control rods by depressurizing the scram discharge air header through redundant exhaust valves.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the functional design of the Hope Creek CRDS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system and demonstrated that the system's ability to affect a safe shutdown, respond within acceptable limits, and prevent or mitigate the consequences of accidents will be maintained following the implementation of the proposed EPU. The NRC staff concludes that the Hope Creek CRDS will continue to meet the requirements of GDCs 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 main steamlines 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 non-brittle manner and that the probability of rapidly propagating fracture is minimized. Specific review criteria are contained in SRP Section 5.2.2 and other guidance provided in Matrix 8 of Power Uprate Review Standard RS-001.[188]

Technical Evaluation

Overpressure protection provided by the Nuclear Pressure Relief System is discussed in Section 5.2.2 of the Hope Creek UFSAR.[189] The SRVs provide overpressure protection for the RCPB, preventing failure of the nuclear system pressure boundary and uncontrolled release of fission products. Hope Creek has fourteen SRVs that discharge into the suppression pool and, together with the reactor scram function, provide overpressure protection. The SRV set points are established to provide the overpressure protection function while ensuring that there is

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Extended Power Uprate" (ELTR2) ADAMS Accession No. ML003712826
188 ADAMS Accession No. ML033640024
189 ADAMS Accession No. ML052220616

adequate pressure difference (simmer margin) between the reactor operating pressure and the SRV actuation set points 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. Therefore, 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 proposed EPU rated thermal power and confirmed the current SRVs setpoints and upper tolerance limits (UTLs) will not change. The ASME Code 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 Code overpressure protection will be confirmed in all the subsequent reload analysis. The NRC staff finds the licensee's assessment that the SRVs will have sufficient capacity to handle the increased steam flow associated with the operation at the EPU power level acceptable.

The design pressure of the Hope Creek reactor vessel and RCPB remains at 1250 psig for EPU operating conditions. The ASME Code allowable peak pressure for the reactor vessel 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 Hope Creek EPU reload cycle. Section 5.5.1.4 of ELTR1[190] evaluated the ASME Code overpressure analysis for power uprate to 20 percent power increase. The potentially limiting pressurization transient events are the MSIV scram on high flux and TT with turbine bypass failure and scram on high flux. However, MSIV closure has been determined **[[ ]]** to be the more limiting event, based on initial core analysis and power uprate evaluations, with respect to reactor over pressure. The licensee analyzed the MSIV closure event based on an initial dome pressure of 1035 psia with one SRV out of service (OOS), at 102 percent of the EPU rated thermal power. The MSIV-position (10 percent closed) anticipatory scram signal 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 1265 psig, which corresponds to vessel bottom head pressure of 1285 psig. Therefore, the peak calculated vessel pressure (1285 psig) remains below the ASME limit of 1375 psig and the maximum calculated reactor dome pressure remains below the TSs SL of 1325 psig. The licensee performed the EPU overpressure protection analysis consistent with the **[[ ]]** analysis in Section 3.8 of ELTR2[191] with the staff-approved transient evaluation computer model ODYN.

The licensee for Hope Creek has established administrative limits and actions to address a leaking SRV due to FIV concerns. The FIV on the Target Rock 2-Stage safety/relief design may result in an inadvertent SRV opening and a "stuck open" SRV condition. This concern is addressed in plant operations procedures which provide immediate response actions. Increased main steam line (MSL) flow, at the proposed Hope Creek EPU operating conditions may affect FIV of the piping and safety/relief valves during normal operation. The vibration frequency, extent and magnitude depend upon plant-specific parameters, valve locations, the valve design and piping support arrangements. The FIV of the main steam piping will be addressed by the licensee by vibration testing during initial plant operation at the higher steam flow rates.

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[190] Appendix K of General Electric Licensing Topical Report (LTR) NEDC-32424P-A (February 1999), "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," (ELTR1) ADAMS Accession No. ML003580231
[191] Supplement 1 of GE Licensing Topical Report, NEDC-32523P-A (February 2000), "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate" (ELTR2) ADAMS Accession No. ML003712826

For the Hope Creek 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 over-pressure 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; its affect on the RCPB design requirement to behave in a non-brittle manner to minimize rapidly propagating failures is unaffected.

Conclusion

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

2.8.4.3 Reactor Core Isolation Cooling System

Regulatory Evaluation

The reactor core isolation cooling (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 reactor vessel. In addition, the RCIC system may provide DHR necessary for coping with an SBO event. The water supply for the RCIC system comes from the condensate storage tank (CST), with a secondary supply from the suppression pool. The NRC staff's review covered the effect of the proposed Hope Creek 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 its ability to perform its 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 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 the fuel design limits are not exceeded; (5) GDC-34, insofar as it requires that a RHR 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 capability 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. Specific review criteria are contained in SRP Section 5.4.6 and other guidance provided in Matrix 8 of Power Uprate Review Standard RS-001.[192]

Technical Evaluation

The Hope Creek RCIC system is described in Section 5.4.6 of the Hope Creek UFSAR.[193] The Hope Creek RCIC system provides core cooling in the event of a transient where the RPV is isolated from the main condenser concurrently with the loss of feedwater flow (LOFWF), and the RPV pressure is greater than the maximum allowable for the initiation of a low-pressure core cooling system.

The RCIC system is located in a Seismic Category I structure of the RB where it is protected against dynamic effects. The licensee states 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 CPPU conditions. This satisfies the GDC that requires SSCs important to safety be protected against dynamic effects. Because Hope Creek is a single unit located at Salem/Hope Creek site complex, the RCIC system satisfies the GDC that requires SSCs important to safety not be shared among other nuclear power units.

The RCIC system is designed to sufficiently maintain reactor water inventory above 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 upon CPPU conditions. **[[**

]] For the Hope Creek EPU, there is no change to reactor dome pressure; thus, the SRVs set points are unchanged and there are no change requirements to the RCIC HP injection parameters. The licensee states that there is no change to the maximum specified reactor pressure for RCIC system operation, **[[**

]]. Therefore, the licensee states that no changes are required to meet the performance requirements for the RCIC system or to limit the maximum startup transient speed peak. Since the performance requirements of the RCIC system are satisfied at the proposed Hope Creek EPU conditions, the GDC that requires: 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) RHR 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 are satisfied. Because no changes were made to the RCIC system, the general design criterion to maintain an extremely high probability of accomplishing its safety functions in an event of an AOOs remains satisfied.

The licensee further states that at EPU operation the **[[**

]]. 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 that assumed only the RCIC system was available to control the RPV water level. The licensee stated that the results

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[192] ADAMS Accession No. ML033640024
[193] ADAMS Accession No. ML052220616

indicate no change to systems and equipment used to respond to a SBO and that the coping time of 4 hours remains unchanged. However, the licensee stated that the RCIC turbine exhaust pressure trip setpoint of 25 psig was exceeded by 1.2 psig; and, furthermore, to provide adequate margin to maintain the RCIC system availability for an SBO event, the licensee plans to revise the RCIC turbine exhaust pressure trip setpoint to at least 30 psig. The licensee stated that raising the exhaust pressure trip setpoint can be accomplished with existing RCIC hardware based on a BWR Owners Group evaluation of RCIC operation with exhaust pressure as high as 50 psig. The LOFW transient event was evaluated for Hope Creek at CPPU conditions, and the plant specific evaluation results indicate adequate water level margin above top of active fuel with only the RCIC available and without any operator action.

The RCIC system leak detection devices will not be changed due to implementation of the Hope Creek EPU. Therefore, the general design criterion that requires that piping systems penetrating the containment be designed with a capability to test periodically the operability of the isolation valves to determine if valve leakage is within acceptable limits is satisfied at the proposed EPU conditions.

The NRC staff finds that the RCIC will continue to meet the NRC's acceptance criteria, as described in the Regulatory Evaluation section above, for the proposed Hope Creek EPU operating conditions, based on the NRC staff's review of the licensee's assessment. The NRC staff finds this acceptable, **[[**

]].

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed Hope Creek EPU on the ability of the RCIC system to provide DHR following a main FW isolation event, an SBO event, and the ability of the system to provide makeup to the core following a small break in the RCPB. The NRC staff concludes that the licensee has 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 NRC staff concludes that the RCIC system will continue to meet the requirements of GDCs 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 design and operation.

2.8.4.4 Residual Heat Removal System

Regulatory Evaluation

The RHR system is used to cool down the RCS following a plant shutdown. The RHR system is typically a LP system which takes over the SDC function when the RCS temperature is reduced. The NRC staff's review covered the effect of the proposed Hope Creek EPU on the functional capability of the RHR system to cool the RCS following shutdown and provide DHR. 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 an RHR system. Specific review criteria are contained in SRP Section 5.4.7 and other guidance provided in Matrix 8 of Power Uprate Review Standard RS-001.[194]

Technical Evaluation

The Hope Creek RHR system is described in Section 5.4.7 of the Hope Creek UFSAR.[195] The RHR system is designed to restore and maintain the reactor coolant inventory and to remove sensible and decay heat from the primary system and containment following reactor shutdown for both normal shutdown and post-accident conditions. The proposed Hope Creek EPU effect on the RHR system would be due to the higher decay heat in the core corresponding to the uprated power and the increase amount of reactor heat discharged into the containment during a LOCA. The RHR system is designed to operate in the SDC mode, LPCI mode, suppression pool cooling (SPC) mode, containment spray cooling (CSC) mode and FPC assist mode. The low-pressure coolant injection (LPCI) mode, as it relates to the LOCA response, is discussed in Section 2.8.5.6.2 of this SE. The effects of EPU on the other modes are discussed below. The results of the following evaluations are consistent with the **[[ ]]** evaluation in Section 4.1 of ELTR2 Supplement 1.[196]

During normal shutdown, the operational objective of the SDC mode is to have the capability to remove decay and sensible heat from the reactor primary system so that the reactor coolant outlet temperature is reduced to 125 °F within approximately 20 hours using two SDC heat exchanger loops after all control rods have been inserted. Although both loops are used for shutdown under normal circumstances, the licensee's SDC analysis demonstrated that the reactor coolant is **[[ ]]**. This SDC performance is within the 24 hour criteria. As part of the Hope Creek Appendix R analysis, SLO of RHR SDC is assumed for DHR in order to achieve cold shutdown within the time required by Appendix R (i.e., 72 hours). An underlying assumption in the Appendix R analysis is that one loop of RHR is unavailable due to the postulated event. The licensee's analysis show that the time required to achieve cold shutdown (i.e., 212 °F) under the Appendix R scenario conditions is less than 24 hours, and therefore, cold shutdown is achieved well within the 72-hour requirement. Since the RHR SDC evaluation at the EPU condition demonstrated that the plant can meet this cool down time, the NRC staff finds it acceptable.

During normal plant operation, the RHR SPC function is to maintain the suppression pool temperature below the TS limit. The SPC mode safety related function is to remove reactor core decay heat and sensible heat discharged to the suppression pool in the event of a DBA or AOOs. Following abnormal events, the SPC function controls the long-term suppression pool temperature such that the maximum operating temperature limit is not exceeded. At the proposed Hope Creek CPPU condition, the reactor decay heat would increase which increases

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[194] ADAMS Accession No. ML033640024
[195] ADAMS Accession No. ML052220616
[196] Section 4.8 of Supplement 1 of GE Licensing Topical Report, NEDC-32523P-A (February 2000), "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate" (ELTR2) ADAMS Accession No. ML003712826

the heat input to the suppression pool during a LOCA, and results in a higher peak suppression pool temperature. The effect of the proposed EPU on the suppression pool after a design basis LOCA is discussed in Section 2.6 of this SE.

The RHR CSC mode provides suppression pool water to the spray headers in the containment to reduce containment pressure and temperature during post-accident conditions. The effect of the containment spray on containment is discussed in Section 2.6 of this SE.

The licensee stated that the higher containment pressure and suppression pool temperature during a postulated LOCA do not affect the hardware capabilities of RHR equipment to perform the LPCI, SPC, and CSC functions.

In the event that the fuel pool heat load exceeds the heat removal capacity of the FPC and cleanup system, FPC assist mode using the RHR heat removal capacity provides supplemental FPC. At CPPU conditions, there is a slight increase in core decay heat loads during refueling. However, the Hope Creek CPPU does not affect the heat removal capability of the FPC assist mode of the RHR system. This mode can be operated with the FPC and cleanup system or separately to maintain the Hope Creek fuel pool temperature within acceptable limits at EPU operating conditions.

Based on the NRC staff's review of the licensee's evaluation and rationale, the NRC staff concurs with the licensee that plant operation at the proposed Hope Creek EPU level will have an insignificant impact on the SDC mode of the RHR system discussed above, and therefore, no modifications are necessary. As stated earlier, the staff evaluation of the rest of the RHR modes will be provided in the SER sections indicated.

Conclusion

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

2.8.4.5 Standby Liquid Control System

Regulatory Evaluation

The SLCS provides backup capability for reactivity control independent of the CRDS. 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. 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 reactor 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, and that the system initiate automatically. Specific review criteria are contained in SRP Section 9.3.5 and other guidance provided in Matrix 8 of Power Uprate Review Standard RS-001.[197]

Technical Evaluation

The Hope Creek SLCS is described in Section 9.3.5 of the Hope Creek UFSAR.[198] The licensee evaluated the effect of the Hope Creek EPU on the SLC system injection and shutdown capability. The Hope Creek SLCS is normally a manually operated system but is also designed to automatically initiate upon receipt of a signal from the redundant reactivity control system (RRCS) logic. The SLCS pumps concentrated sodium pentaborate solution into the reactor vessel in order to provide neutron absorption and is capable of bringing the reactor to a subcritical shutdown condition from rated thermal power in the postulated condition that all or some of the control rods cannot be inserted.

The licensee stated that an **[[**

]]. In addition, no system modifications are required as a result of EPU.

The licensee performed a plant specific ATWS analysis and stated that the peak calculated vessel upper plenum pressure during SLCS operation is 1179 psia for the limiting event. In the ATWS analysis, it was assumed that at least one of the set of five SRVs, set at 1130 psig, opens during the SLCS injection period. Consequently, there is a corresponding increase in the maximum pump discharge pressure and decrease in the operating pressure margin for the pump discharge relief valves. The pressure margin for the pump discharge relief valves remains above the minimum value needed to assure that the relief valves remain closed during system injection. In the event that the SLCS is initiated before the time that reactor pressure recovers from the first transient peak, resulting in opening of the SLCS relief valves, the reactor pressure must reduce sufficiently to ensure SLCS relief valve closure. The licensee stated that the analytical results indicate that the reactor pressure reduces sufficiently from the first transient peak to allow the SLCS relief valves to close.

10 CFR 50.62(c)(4) requires that each BWR must have an SLCS with the capability of injecting into the RPV a borated water solution at such a flow rate, level of boron concentration and boron-10 isotope enrichment, and accounting for RPV volume, that the resulting reactivity control is at least equivalent to that resulting from injection of 86 gallons per minute (gpm) of 13 weight percent sodium pentaborate decahydrate solution at the natural boron-10 isotope abundance into a 251-inch ID RPV for a given core design. For ATWS, the equivalency requirement of the rule can be met if the following relationship is satisfied:

[197] ADAMS Accession No. ML033640024
[198] ADAMS Accession No. ML052220616

(Q/86) x (M251/M) X (C/13) X (E/19.8) > 1

where:
Q= expected SLCS flow rate (gpm)
M= mass of water in the reactor vessel and recirculation system at hot rated condition in lbs
C= sodium pentaborate solution concentration (weight percent)
E= Boron-10 isotope enrichment (19.8 percent of natural boron)
M251= mass of water in a BWR/4 251 inches diameter reactor vessel (lbs)=628300 lbs

The licensee performed plant specific calculations to verify that the SLCS complies with the ATWS rule referred above. RRCS will initiate both SLCS pumps during an ATWS event. Using the following Hope Creek specific values to satisfy the relationship given above, the licensee established the bases for meeting the ATWS rule.

Q= 82.4 GPM
C= 13.6 weight percent
M= 628300 lbs

(82.4/86) x (628300/628300) X (13.6/13) X (19.8/19.8) = 1.002
1.002 > 1

The combination of boron concentration, natural boron, and pump flow rate satisfies the relationships given above. This provides a minimum flow capacity and boron content equivalent in control capacity to 86 GPM of 13 weight percent of sodium pentaborate solution. By using the flow rate of both pumps and weight percent of sodium pentaborate solution, the necessary 86 GPM equivalency requirements of 10 CFR 50.62(c)(4) for the SLCS is satisfied. Therefore, Hope Creek is able to meet the equivalency requirement of the rule.

CRD system and SLCS provide two independent reactivity control systems. The system capability of either of them to make the core subcritical under any conditions is unaffected by the proposed Hope Creek EPU.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the Hope Creek SLCS and concludes that the licensee has adequately accounted for the effects of the proposed EPU 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 EPU. Based on this, the NRC staff concludes that the Hope Creek SLCS will continue to meet the requirements of GDCs 26 and 27, and 10 CFR 50.62(c)(4) following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the SLCS.

2.8.5 Accident and Transient Analyses

Nuclear plant AOOs are transients which 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 by personnel error. The applicable acceptance criteria for the AOOs are based on 10 CFR Part 50, Appendix A, GDCs 10, 15, 20, 25, 26, 27, 28, 31 and 35.

Nuclear plant DBAs are not expected to occur but are used in the design of nuclear power plants to establish the performance requirements for SSCs, including the safety related ECCS. More serious accidents that may involve significant core degradation and/or pose the real danger of a significant release of radiation to the environment are classified as beyond DBA or severe accidents. These accidents have an extremely low probability of occurrence and are postulated to assure that the radiological dose is maintained within applicable regulatory requirements. The applicable acceptance criteria for DBA such as LOCAs are based on 10 CFR Part 50.46, 10 CFR Part 50, Appendix K and GDCs 4, 27 and 35.

Section 15 of the Hope Creek UFSAR[199] 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 response to the limiting transients are analyzed at each reload cycle and are used to establish the fuel thermal limits. In this section, the analyses include AOOs in the following categories: (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. Section 15 also evaluates the following DBA events: CRDA, LOCA, Refueling Accident, MSLB Accident. Radiological consequences of DBA are also addressed.

The NRC approved generic guidelines (Appendix E of ELTR1)[200] for an EPU application including identification of the set of limiting transients to be evaluated in specific event categories for the EPU reactor core. Among the listed event categories, the following transients were evaluated in the Hope Creek PUSAR:[201]

Fuel thermal margin events:

LRNBP (load rejection, no bypass) ⋘ Most limiting

TTNBP (turbine trip, no bypass) ⋘ Most limiting
FWCF (feedwater controller failure)
LFWH (loss of feedwater heating)
RWE (rod withdrawal error)
SRI (slow recirculation increase)
FRI (fast recirculation increase)
LRWBP (load rejection, with bypass)
MSIVA (MSIV closure with all valves)
MSIVO (MSIV closure with one valve)

[199] ADAMS Accession No. ML052220616
[200] General Electric Licensing Topical Report (LTR) NEDC-32424P-A (February 1999), "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," (ELTR1) ADAMS Accession No. ML003680231
[201] Attachment 4 to PSEG letter (LR-N06-0286) to NRC dated September 18, 2006, “Request for License Amendment Extended Power Uprate, Hope Creek Generating Station, Facility Operating License NPF-57, Docket No. 50-354” ADAMS Accession No. ML062680451

Limiting transient overpressure events:

MSIVF (MSIV closure with flux scram) ⋘ Most limiting

Limiting loss of water level transients:

LOFW (loss of feedwater flow) ⋘ Most limiting
LOOFP (loss of one feedwater pump)

The Pressure Regulator Downscale (PRDS) failure, TTNBPF (Turbine trip, no bypass with flux scram) and Inadvertent HPCI start listed in Table E-1 of ELTR1[202] were not analyzed because of the following justifications. PRDS was included in the list of BWR/6 plants for reload evaluation according to ELTR1, Section 5.3.2. Hope Creek is a BWR/4 plant and thus this event is not applicable. TTNBPF is determined to be **[[ ]]** non-limiting compared to the MSIV closure due to the differences in the dynamic response and the increased steam volume associated with a TT stop valve closure. Thus, TTNBPF is not analyzed in the Hope Creek PUSAR.[203] The inadvertent HPCI start event for Hope Creek is bounded by a LFWH event, which was confirmed in previous reload licensing calculation. For the Hope Creek proposed EPU application, HPCI flow is unchanged and becomes a smaller percentage of the uprated FW flow. The reduced percentage decreases the relative amount of subcooling from the HPCI and the margin is increased compared to CLTP for this event. In addition, Hope Creek's HPCI has more than 30 percent flow diverted to CS sparger, which will not increase core inlet subcooling. Thus the event is considered not limiting and not analyzed.

It is shown by precedent power uprate applications that the characteristics of the AOO events that determine the OLMCPR do not change significantly when reactor power is increased up to 120 percent for CPPU operation. The results of the limiting thermal margin analyses depend upon the core design, loading pattern, etc., and will be analyzed for the "actual" EPU core in each cycle specific reload analysis. Thus, this deviation of limiting transient analysis sets from the ELTR1[202] with justifications is acceptable.

In the Hope Creek EPU transient and accident analyses, the licensee used NRC staff-approved methods. Most of the transient events except the LOFW and MSIVF events (analyzed at a 102 percent rated EPU power) are analyzed at the full EPU power and maximum allowed core flow point on the Hope Creek EPU power/flow map. Direct or statistical allowance for 2 percent power uncertainty is included in the analysis. One of the lowest pressure set point SRVs is assumed to be out of service. In transient analysis, the decay heat model is important since it affects the hydraulic response after reactor scram. Hope Creek CYCLE 15 has a mixed core of GE14 fuels and legacy SVEA 96+ fuels. The analysis uses the equilibrium core (GE14) as an assumption that the GE14 equilibrium core will bound the mixed core calculation. The justification for this assumption is that the decay heat is not a strong function of fuel product line or manufacturer. A comparison study had been performed to compare the ANS 5.1-1979 standard decay heat result of a SVEA 96+ fuel with that of a GE14 bundle of comparable enrichment. The resulting differences are well within the calculation uncertainties, and hence

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[202] General Electric Licensing Topical Report (LTR) NEDC-32424P-A (February 1999), "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," (ELTR1) ADAMS Accession No. ML003680231
[203] Attachment 4 to PSEG letter (LR-N06-0286) to NRC dated September 18, 2006, "Request for License Amendment Extended Power Uprate, Hope Creek Generating Station, Facility Operating License NPF-57, Docket No. 50-354" ADAMS Accession No. ML062680451

the Hope Creek EPU decay heat assumption remains valid for a mixed core of SVEA 96+/GE14.[204]

The GEMINI transient analysis methods (Appendix E of ELTR1) were used for the licensee evaluations of the Hope Creek AOOs. Most system transients were evaluated with the ODYN code combined with the TASC code for the MCPR calculations. The ODYN code uses a one-dimensional kinetics model that considers time-dependent spatial variation in the axial direction, using one-energy-group diffusion theory with six delayed neutron groups and neutron diffusion parameters from collapsed three-dimensional steady-state conditions. The ODYN code is used to predict reactor key parameter responses including power, pressure, temperature, void, water level and core flow.

Hope Creek has a reliable RPS and an independent reactivity control system (SLCS) installed. The capability to bring the core to subcritical state under any conditions is unaffected by the proposed Hope Creek EPU. Thus conformance to GDC-20 and GDC-26 are ensured.

In summary, the transients analyzed with approved methodology in the Hope Creek PUSAR[205] 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, LRNBP (load rejection, no bypass) and TTNBP (turbine trip, no bypass) are the most limiting transients (with a delta (Δ) CPR of 0.27) in the fuel thermal margin event category and is used to establish the Hope Creek OLMCPR (1.42) limits for the proposed EPU. In terms of fuel thermal protection, this group of transients is acceptable. The MSIVF is the most limiting event in the overpressure transient category. Analysis in the Hope Creek PUSAR 3.1 shows a maximum reactor pressure of 1285 psig, which is less than the 1375 psig ASME limit. Thus this category of transients is acceptable. The LOFW is the most limiting event in the loss of water level transient category. The lowest level inside core shroud is 80 inches above TAF. Thus, no core uncover is expected and thus this group of transients is also acceptable.

The following sections provide the NRC staff's evaluation of the licensee's accident and transient analyses for the proposed EPU.

2.8.5.1 Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Main Steam Relief or Safety 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 SDM. 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

[204] PSEG letter (LR-N07-0035) to NRC dated March 13, 2007, "Response to Request for Additional Information Request for License Amendment - Extended Power Uprate" ADAMS Accession No. ML070790508
[205] Attachment 4 to PSEG letter (LR-N06-0286) to NRC dated September 18, 2006, "Request for License Amendment Extended Power Uprate, Hope Creek Generating Station, Facility Operating License NPF-57, Docket No. 50-354" ADAMS Accession No. ML062680451

requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations including AOOs; (2) GDC-15, insofar as it requires that the RCS and its associated auxiliary systems be designed with margin sufficient to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; (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. Specific review criteria are contained in SRP Section 15.1.1-4 and other guidance provided in Matrix 8 of RS-001.[206]

Technical Evaluation

Transients in this category include LFWH, increase in FW flow, increase in steam flow, and inadvertent opening of a main steam relief or safety valve. Among these transients, LFWH is the most limiting event according to ELTR1. A FW heater can be lost in case: (1) 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; and (2) a bypass line opens so that the FW flow is bypassed instead of running through the heater. In either case, the reactor vessel receives cooler FW which produces an increase in core inlet subcooling. Due to negative moderator temperature feedback, it results in an increase of reactivity and power. A scram on high APRM thermal power may occur.

LFWH was analyzed in PUSAR 9.1.1. The calculated ΔCPR is 0.17 (shown in PUSAR Table 9-2), which is bounded by other transients in terms of fuel thermal margin, e.g. TTNBP or LRNBP (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, this group of transients is acceptable.

EVENT	DISPOSITION
Loss of Feedwater Heater	Evaluated in PUSAR 9.1.1
Increase in Feedwater Flow	Non-Limiting event, not analyzed
Increase in Steam Flow	Non-Limiting event, not analyzed
Inadvertent Opening of a Main Steam Relief or Safety Valve	Non-Limiting event, not analyzed

Conclusion

The NRC staff has reviewed the licensee's analyses of the excess heat removal events described above and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB

[206] ADAMS Accession No. ML033640024

pressure limits will not be exceeded as a result of these events. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, 20, and 26 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the events stated.

2.8.5.2 Decrease in Heat Removal by the Secondary System

2.8.5.2.1 Loss of External Load; Turbine Trip; Loss of Condenser Vacuum; 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 by the secondary system. These events result in a sudden reduction in steam flow and, consequently, result in pressurization events. Reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered the sequence of events, the analytical models used for analyses, the values of parameters used in the analytical models, and the results of the transient analyses. The NRC's acceptance criteria are based on: (1) GDC-10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC-15, insofar as it requires that the RCS and its associated auxiliary systems be designed with margin sufficient to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; and (3) GDC-26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.2.1-5 and other guidance provided in Matrix 8 of RS-001.[207]

Technical Evaluation

This category of transients includes loss of external load, TT, loss of condenser vacuum, closure of main steam isolation valve and steam pressure regulator failure (closed). According to ELTR1, loss of condenser vacuum and steam pressure regulator failure are not limiting compared to the rest of the group.

[[ ]] analyses performed in ELTR1 indicated that MSIV closure with flux scram event (MSIVF) is the most limiting transient for pressurization events. The MSIVF was analyzed in PUSAR 3.1. The results show a peak reactor bottom pressure of 1285 psig. It is within the acceptance criterion of 1375 psig (ASME 110 percent of design pressure 1250 psig). Hence, RCPB design limit is not exceeded. This event is considered as infrequent event instead of AOO. Thus MSIVF is not used to establish thermal margin.

Other transients in this group are evaluated to ensure SAFDL are not exceeded through establishing operating limit of MCPR. Load rejection without bypass (LRNBP) event was evaluated in PUSAR 9.1.1. In this event, a loss of generator electrical load from high power conditions initiates main turbine control valve fast closure. Turbine control valve closure is sensed by the RPS, and it activates the reactor scram. The results of this event show a Delta CPR of 0.27 (PUSAR Table 9-2). Turbine trip with no bypass (TTNBP) event was also

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[207] ADAMS Accession No. ML033640024

evaluated in the PUSAR 9.1.1. A variety of turbine or nuclear system malfunctions could initiate a TT. Once initiated, all of the main TSVs close within about 0.01 second. Analysis of TTNBP shows Delta CPR of 0.27 (PUSAR Table 9-2). These two transients are the limiting events among the analyzed set in PUSAR Table 9-2. They are used to establish OLMCPR for fuel thermal limit protection. As long as OLMCPR is not exceeded, SAFDL are guaranteed.

The MSIV closure in one of the four steam lines and all four steam lines were analyzed in the PUSAR 9.1.1. They show Delta CPR of 0.11 and 0.18 respectively. They are bounded by LRNBP and TTNBP.

Since GDC 10, 15 and 26 are met, this group of transients is acceptable.

EVENT	DISPOSITION
Loss of External Load	Evaluated in the PUSAR 9.1.1
Turbine Trip No Bypass	Evaluated in the PUSAR 9.1.1
Loss of Condenser Vacuum	Non-Limiting event according to ELTR1, not analyzed
Closure of Main Steam Isolation Valve	MSIVD evaluated in the PUSAR 9.1.1, bounded by LRNBP and TTNBP MSIVF evaluated in the PUSAR 3.1, limiting in reactor pressure

Conclusion

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

2.8.5.2.2 Loss of Nonemergency AC Power to the Station Auxiliaries

Regulatory Evaluation

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

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 itself. The turbine trip with no bypass (TTNBP) event bounds this event because the loss of non-emergency AC power event causes a delayed TT with a recirculation pump trip (RPT). The introduced reactivity will be less than regular TTNBP. LRNBP and TTNBP are addressed in Section 2.8.5.2.1 of this SER and they are acceptable. Therefore, this event is well bounded by other transients.

Also according to ELTR1 evaluation, Loss of Auxiliary Power to the Station Auxiliaries is a nonlimiting event for all GE BWRs. This event is not analyzed.

Conclusion

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

2.8.5.2.3 Loss of Normal Feedwater Flow

Regulatory Evaluation

A LOFW could occur from pump failures, valve malfunctions, or a LOOP. LOFW 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 analyses; (3) the values of parameters used in the analytical model; and (4) the results of the transient analyses. The NRC's acceptance criteria are based on: (1) GDC-10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC-15, insofar as it requires that the RCS and its associated auxiliary systems be designed with margin sufficient to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; and (3) GDC-26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.2.7 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

Feedwater control system failure or reactor FW pump trip can lead to partial or complete LOFW. LOFW results in a situation where the mass of steam leaving the reactor vessel exceeds the mass of water entering the vessel, resulting in a decrease in the coolant inventory available for core cooling. According to ELTR1 Appendix E.2.2, the safety criteria for the LOFW event (maintenance of adequate transient core cooling) is met by maintaining the water level (inside the core shroud) above the top of the core.

Hope Creek performed a plant-specific calculation in the PUSAR with a representative equilibrium GE-14 core for LOFW event following the ELTR-1/2 approach. One important factor of this event is decay heat model since it affects the level recovery. Hope Creek CYCLE 15 has a mixed core of GE14 fuels and legacy SVEA96+ fuels. As mentioned in the introduction, the analysis uses the equilibrium core (GE14) as an assumption that the GE14 equilibrium core will bound the mixed core calculation. The justification for this assumption is that the decay heat is not a strong function of fuel product line or manufacturer. A comparison study had been performed to compare the ANS 5.1-1979 Standard decay heat result of an SVEA 96+ fuel with that of a GE14 bundle of comparable enrichment. The resulting differences are well within the calculation uncertainties, and hence the HCGS EPU decay heat assumption remains valid for a mixed core of SVEA 96+/GE14.[208] This analysis also assumed failure of the HPCI system and used only the RCIC system to restore the reactor water level.

The increased decay heat due to EPU operation results in a slower reactor water level recovery compared to 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 80 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, the response to this transient is acceptable under EPU condition.

Conclusion

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

[208] PSEG letter (LR-N07-0035) to NRC dated March 13, 2007, "Response to Request for Additional Information Request for License Amendment - Extended Power Uprate" ADAMS Accession No. ML070790508

2.8.5.3 Decrease in Reactor Coolant System Flow

2.8.5.3.1 Loss of Forced Reactor Coolant Flow

Regulatory Evaluation

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

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 due to loss of non-emergency AC power. When the drive motor breakers are tripped, the motor-generators will continue to supply some reduced power to their respective recirculation pump motors, due to the time required for the motorgenerator sets 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. Critical power will reduce due to core flow reduction but the operating power will sustain for a little while. This combination causes the calculated MCPR to decrease to a lower value but not to SLMCPR. The fuel thermal margin is influenced by the rotating inertia of the motor-generator sets since it determines the pump coast down speed.

Generic analyses performed for several BWRs have shown that the events in this category are not limiting and are bounded by other more limiting transients. Therefore, these events are not included in ELTR1 for the EPU evaluation.

EVENT	DISPOSITION
Recirculation flow controller failure- Decreasing flow	Not analyzed, non-limiting
Trip of one recirculation pump	Not analyzed, non-limiting
Simultaneous trip of both recirculation pumps	Not analyzed, non-limiting

Conclusion

The NRC staff has reviewed the licensee's analyses of the decrease in reactor coolant flow event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the decrease in 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 break of the shaft of a reactor recirculation pump. Flow through the affected loop is rapidly reduced, leading to a reactor and TT. The sudden decrease in core coolant flow while the reactor is at power results in a degradation of core heat transfer which could result in fuel damage. The initial rate of reduction of coolant flow is greater for the rotor seizure event. However, the shaft break event permits a greater reverse flow through the affected loop later during the transient and, therefore, results in a lower core flow rate at that time. In either case, reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered: (1) the postulated initial and long-term core and reactor conditions; (2) the methods of thermal and hydraulic analyses; (3) the sequence of events; (4) the assumed reactions of reactor system components; (5) the functional and operational characteristics of the RPS; (6) operator actions; and (7) the results of the transient analyses. The NRC's acceptance criteria are based on: (1) GDC-27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; (2) GDC-28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel 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 assure that, under specified conditions, it will behave in a non-brittle manner and the probability of a rapidly propagating fracture is minimized. Specific review criteria are contained in SRP Section 15.3.3-4 and other guidance provided in Matrix 8 of RS-001.[209]

Technical Evaluation

Recirculating pump rotor seizure and shaft break are DBAs. Flow through the affected loop is rapidly reduced, leading to a reactor and TT. 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 uncover is not expected during this accident.

Events in this category, with exception of SLO pump seizure, are not limiting for any GE BWR. SLO pump seizure was analyzed in the Hope Creek MCAR (ML053190325) for Cycle 13 and 14 to establish cycle-independent OLMCPR (1.51 for SLO). **[[ ]]** analyses performed for several BWRs have shown that the accidents in this category are not limiting and are bounded by more limiting event, i.e. Turbine Trip without bypass. Thus, these accidents are not included in ELTR1 for the EPU evaluation.

Since there are no changes to recirculation pumps, the staff believes that Hope Creek continues to meet the limits in EPU operation. The staff believes that Hope Creek RCPB is designed with sufficient margin for this non-limiting 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.

EVENT	DISPOSITION
Recirculation pump shaft break	Not analyzed, bounded by recirculation pump rotor seizure
Recirculation pump rotor seizure	Not analyzed, bounded by other DBAs

Conclusion

The NRC staff has reviewed the licensee's analyses of the sudden decrease in core coolant flow events and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the ability to insert control rods is maintained, the RCPB pressure limits will not be exceeded, the RCPB will behave in a non-brittle 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 GDCs 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.

[209] ADAMS Accession No. ML033640024

2.8.5.4 Reactivity and Power Distribution Anomalies

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

Regulatory Evaluation

An uncontrolled control rod assembly withdrawal from subcritical or low power startup conditions may be caused by a malfunction of the reactor control or rod control systems. This withdrawal will uncontrollably add positive reactivity to the reactor core, resulting in a power excursion. The NRC staff's review covered: (1) the description of the causes of the transient and the transient itself; (2) the initial conditions; (3) the values of reactor parameters used in the analysis; (4) the analytical methods and computer codes used; and (5) the results of the transient analyses. The NRC's acceptance criteria are based on : 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 automatically initiate the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded as a result of AOOs; and (3) GDC-25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems. Specific review criteria are contained in SRP Section 15.4.1 and other guidance provided in Matrix 8 of RS-001.[210]

Technical Evaluation

The RWE event, a continuous withdrawal of an out-of-sequence rod during a reactor startup from a subcritical or low power condition, is described in Hope Creek UFSAR Section 15.4.1.2 and UFSAR Appendix 15B. 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 prior to safety system actuation. In low power range, 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 non-limiting events, and are not re-analyzed as part of the reload analysis.

In EPU operation, the Hope Creek RWM low power set point (LPSP) is kept at the same absolute power value following ELTR1 guideline. However, TS will change since the LPSP measurement parameter is based on steam flow and the instrumentation is being replaced due to power uprate. Thus the rod movement sequence in startup range will not be affected by EPU. Since this event assumes failure of RWM, the change of EPU RWM operation does not affect the result of analysis in terms of reactivity insertion to fuel.

Considering reactivity insertion in this event, the analysis described in UFSAR Appendix 15B demonstrates maximum reactivity insertion of 60 calories per gram (cal/gm), which has considerable margin for the peak fuel enthalpy for both GE and SVEA fuel to the acceptable limit of 170 cal/gm. At the uprated power with same initial condition, it is assumed that a higher fuel enthalpy (20 percent increase from 60 to 72 cal/gm) can be reached due to higher

[210] ADAMS Accession No. ML033640024

enrichment or other changes.[211] But the peak fuel enthalpy remains far below the 170 cal/gm limit. The current licensing basis for this event is not altered by the EPU operation. Thus it is acceptable.

Conclusion

The NRC staff has reviewed the licensee's analyses of the uncontrolled control rod assembly withdrawal from a subcritical or low power startup condition and concludes that the licensee's analyses have adequately accounted for the changes in core design necessary for operation of the plant at the proposed power level. The NRC staff also concludes that the licensee's analyses were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure the SAFDLs are not exceeded. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 20, and 25 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the uncontrolled control rod assembly withdrawal from a subcritical or low power startup condition.

2.8.5.4.2 Uncontrolled Control Rod Assembly Withdrawal at Power

Regulatory Evaluation

An uncontrolled control rod assembly withdrawal at power may be caused by a malfunction of the reactor control or rod control systems. This withdrawal will uncontrollably add positive reactivity to the reactor core, resulting in a power excursion. The NRC staff's review covered: (1) the description of the causes of the AOO and the description of the event itself; (2) the initial conditions; (3) the values of reactor parameters used in the analysis; (4) the analytical methods and computer codes used; and (5) the results of the associated analyses. The NRC's acceptance criteria are based on: (1) GDC-10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC-20, insofar as it requires that the RPS be designed to initiate automatically the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded as a result of AOOs; and (3) GDC-25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems. Specific review criteria are contained in SRP Section 15.4.2 and other guidance provided in Matrix 8 of RS-001.[212]

Technical Evaluation

The RWE at power level is categorized as a limiting AOO and is re-analyzed for each reload. While operating in the power range, it is assumed in this event that the reactor operator makes a procedural error and fully withdraws the maximum worth control rod. Due to the positive reactivity insertion, the core average power increases. If the rod withdrawal error is severe enough, the RBM will activate alarms and the operator will take corrective actions. 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 fuel thermal overpower limit and fuel rod mechanical overpower limits should not be exceeded.

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[211] ADAMS Accession No. ML071360374
[212] ADAMS Accession No. ML033640024

In PUSAR, this event was analyzed in EPU condition with ΔCPR of 0.17. The rod block monitor is no longer credited in the analysis of this event.[213] The analysis result is bounded by other transients with enough thermal margin. Thus, the plant response to this event is acceptable.

Conclusion

The NRC staff has reviewed the licensee's analyses of the uncontrolled control rod assembly withdrawal at power event and concludes that the licensee's analyses have adequately accounted for the changes in core design required for operation of the plant at the proposed power level. The NRC staff also concludes that the licensee's analyses were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure the SAFDLs are not exceeded. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 20, and 25 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the uncontrolled control rod assembly withdrawal at power.

2.8.5.4.3 Startup of a Recirculation Loop at an Incorrect Temperature and Flow Controller Malfunction Causing an Increase in Core Flow Rate

Regulatory Evaluation

A 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 due to decreased moderator temperature and core void fraction (VF). The NRC staff's review covered: (1) the sequence of events; (2) the analytical model; (3) the values of parameters used in the analytical model; and (4) the results of the transient analyses. The NRC's acceptance criteria are based on: (1) GDC-10, insofar as it requires that the RCS be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs; (2) GDC-20, insofar as it requires that the protection system be designed to 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 condition of the RCPB are not exceeded during AOOs; (4) GDC-28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core; and (5) GDC-26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.4.4-5 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

Events in this category include recirculation flow controller failure (increasing flow) and start-up of idle recirculation pump. According to ELTR1, the transients in this category are not limiting events for power uprate up to 20 percent. But the events need to be re-evaluated to confirm on a plant specific basis.

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[213] ADAMS Accession No. ML070790508

Start-up of an idle recirculation pump is a non-limiting transient for GE BWRs that have the ARTS plant performance option. Hope Creek has been approved with ARTS/MELLLA implementation.[214] Thus this event is not re-analyzed.

Flow dependent thermal power operating limits, MCPR(f), LGHRFAC (f) and MAPFAC (f) are developed to ensure that fuel thermal limits are not violated for the limiting flow increase transients. These flow-dependent limits are generic ARTS program limits and are derived from a conservative two recirculation pump slow flow runout test. These flow-dependent limits for core flow increase transients were confirmed at the GE14 fuel introduction in Hope Creek. For SRI event documented in PUSAR Table 9-2, the OLMCPR is MCPR(f) and thus the thermal limits are not violated.

FRI event is performed in PUSAR (Table 9-2) with more limiting initial condition. The result shows a Delta CPR of 0.22 and the OLMCPR is bounded by off rated flow limits. Since the Delta CPR is not limiting compared to other transients and the OLMCPR is bounded, this event is acceptable.

EVENT	DISPOSITION
Start-up of an Idle recirculation loop	Not re-analyzed, non-limiting event
Recirculation flow controller failure- slow Increasing Flow	Analyzed, non-limiting event, OLMCPR is MCPR(f)
Recirculation flow controller failure- fast Increasing Flow	Analyzed, non-limiting event, OLMCPR is bounded by off rated flow limits

Conclusion

The NRC staff has reviewed the licensee's analyses of the increase in core flow event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, 20, 26, and 28 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the increase in core flow event.

2.8.5.4.4 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 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

[214] Hope Creek Generating Station APRM/RBM/Technical Specifications/Maximum Extended Load Line Limit Analysis (ARTS/MELLLA)," NEDC-33066P, Revision 2, February 2005. ADAMS Accession No. ML052030313

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 reactor vessel internals so as to significantly impair the capability to cool the core. Specific review criteria are contained in SRP Section 15.4.9 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

CRDA is a DBA analyzed in Section 15.4.9 of UFSAR. 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 unto the withdrawn drive coupling. The rate of positive reactivity insertion into reactor core is consistent with the maximum control rod drop velocity. Neutron flux increases and fuels are heated up. Eventually high neutron flux trips the RPS and the reactor scrams.

According to UFSAR, Hope Creek is a Banked Position Withdrawal Sequence (BPWS) plant. According to GESTAR II (GE Nuclear Energy, "General Electric Standard Application for Reactor Fuel," NEDE-24011-P-A-14, June 2000), it does not need to analyze the CRDA at each reload. A bounding generic evaluation in GESTAR II has been performed and the results show that the resultant peak fuel enthalpy (135 cal/gm) will not exceed the 280 cal/gm limit. In terms of the increased RCPB stress, the analysis in GESTAR II showed about 15 psi increase for this event, which would not cause applicable ASME stress limits to be exceeded. Thus re-analysis of this event is not required in each reload. In PUSAR, a compliance evaluation was performed. Same initial condition was assumed for EPU and peak enthalpy was assumed 20 percent higher than generic peak fuel enthalpy (from 135 to 162 cal/gm). It confirms that the peak fuel enthalpy is still well within the limit of 280 cal/gm.

The radiological consequence of this accident is analyzed in the application using CPPU core inventory guidance in Appendix C of Regulatory Guide 1.183. The post-CRDA EAB, LPZ and CR doses are within applicable regulatory limits summarized in PUSAR Table 9-7. They are acceptable.

Conclusion

The NRC staff has reviewed the licensee's analyses of the rod drop accident and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that appropriate reactor protection and safety systems will prevent postulated reactivity accidents that could: (1) result in damage to the RCPB greater than limited local yielding; or (2) cause sufficient damage that would significantly impair the capability to cool the core. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDC-28 following implementation of the EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the rod drop accident.

2.8.5.5 Inadvertent Operation of ECCS 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 over pressurization of the RCS. Alternatively, a power level decrease and depressurization may result. Reactor protection and safety systems are actuated to mitigate these events. The NRC staff's review covered: (1) the sequence of events; (2) the analytical model used for analyses; (3) the values of parameters used in the analytical model; and (4) the results of the transient analyses. The NRC's acceptance criteria are based on: (1) GDC-10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC-15, insofar as it requires that the RCS and its associated auxiliary systems be designed with 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. Specific review criteria are contained in SRP Section 15.5.1-2 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

As mentioned earlier in the introduction, inadvertent HPCI start event was analyzed in previous reload licensing. The analysis confirmed that the LOFWH event bounds the HPCI event. Thus this event was not analyzed.

The FWCF to maximum demand is the most limiting event in vessel inventory increase category according to ELTR1 and was evaluated in PUSAR. This event starts when the FW flow controller fails to the maximum demand value. This causes a rapid increase in FW flow. The core inlet temperature reduces and positive reactivity is introduced and power increases. The reactor water level increases until high water level (L8) set-point is reached. When L8 is reached, the main TTs, the FW pumps trip and a reactor scram is initiated as a consequence of the TT.

The results shown in PUSAR Table 9-2 indicated this event (delta CPR = 0.23) is bounded by Turbine Trip with Bypass Failure (delta CPR = 0.27). Hence, the SAFDL are met and this category of events is acceptable.

Conclusion

The NRC staff has reviewed the licensee's analyses of the inadvertent operation of ECCS or malfunction that increases reactor coolant inventory and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the inadvertent operation of ECCS or 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 there is no reactor trip. The pressure regulator senses the RCS pressure decrease and partially closes the turbine control valves (TCVs) to stabilize the reactor at a lower pressure. The reactor power settles out at nearly the initial power level. The coolant inventory is maintained by the FWC system 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 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. Specific review criteria are contained in SRP Section 15.6.1 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

Inadvertent opening of a safety/relief valve will cause a decrease in reactor coolant inventory and result in mild depressurization. The pressure regulator senses the reactor pressure decrease and closes the TCV far enough trying to maintain constant reactor vessel pressure. Automatic recirculation flow control system increases the recirculation flow to the maximum to compensate the power reduction. Reactor power settles out at nearly the initial power level. Because the recirculation flow control can not meet the additional load demand, the pressure regulator set is automatically reduced to a lower limit, and the reactor pressure decreases eventually.

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. According to ELTR1, the bounding event for this category (decrease in reactor coolant inventory) is LOFW. Thus, this transient is not listed in the minimum required tests in ELTR1 and hence not analyzed.

Conclusion

The NRC staff has reviewed the licensee's analyses of the inadvertent opening of a pressure relief valve event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the inadvertent opening of a 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 reactor protection and ECCS systems are provided to mitigate these accidents. The NRC staff's review covered: (1) the licensee's determination of break locations and break sizes; (2) postulated initial conditions; (3) the sequence of events; (4) the analytical model used for analyses, and calculations of the reactor power, pressure, flow, and temperature transients; (5) calculations of peak cladding temperature (PCT), total oxidation of the cladding, total hydrogen generation, changes in core geometry, and long-term cooling; (6) functional and operational characteristics of the reactor protection and ECCS systems; and (7) operator actions. The NRC's acceptance criteria are based on: (1) 10 CFR 50.46, insofar as it establishes standards for the calculation of ECCS performance and acceptance criteria for that calculated performance; (2) 10 CFR Part 50, Appendix K, insofar as it establishes required and acceptable features of evaluation models for heat removal by the ECCS after the blowdown phase of a LOCA; (3) GDC-4, insofar as it requires that SSCs important to safety be protected against dynamic effects associated with flow instabilities and loads such as those resulting from water hammer; (4) GDC-27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; and (5) GDC-35, insofar as it requires that a system to provide abundant emergency core cooling be provided to transfer heat from the reactor core following any LOCA at a rate so that fuel clad damage that could interfere with continued effective core cooling will be prevented.

Specific review criteria are contained in SRP Sections 6.3 and 15.6.5 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

The ECCS of HCGS is described in Section 15.6.5 of the HCGS UFSAR. ECCS components are designed to provide protection in the event of a LOCA due to 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 the 10 CFR Part 100 limits. For a LOCA, 10 CFR 50.46 specifies design acceptance criteria based on: (1) the PCT; (2) local cladding oxidation, total hydrogen generation; (3) coolable core geometry; and (4) long-term cooling. The LOCA analysis considers a spectrum of break sizes and locations, including a rapid circumferential rupture of the largest recirculation system pipe. Assuming a single failure of the ECCS, the LOCA analysis identifies the break sizes that most severely challenge the ECCS systems and the primary containment. The MAPLHGR operating limit is based on the most limiting LOCA analysis, and licensees perform LOCA analyses for each new fuel type to demonstrate that the 10 CFR 50.46 acceptance criteria can be met.

The ECCS for HCGS includes the HPCI system, the LPCI mode of the RHR, the CS system and the ADS.

High Pressure Coolant Injection (HPCI)

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

HPCI performance is **[[ ]]** evaluated in Section 4.2 of ELTR-2 for a reactor operating pressure increase of up to 75 psi. The licensee stated that **[[**

.]] The **[[ ]]** evaluation concludes that the HPCI pump and turbine remain within their allowable operating envelopes, 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.

Therefore, the HCGS HPCI system was evaluated for EPU conditions, and is consistent with the bases and conclusions of the generic evaluation in Section 4.2 of ELTR-2. Since the licensee's ECCS-LOCA analysis (see section below titled, "ECCS Performance") based on the current HPCI capability demonstrate that the system provides adequate core cooling, the staff finds the evaluation acceptable, and agree with the licensee's assessment that the HPCI will continue to meet the NRC's acceptance criteria, as outlined in the Regulatory Evaluation section above.

Core Spray (CS)

The CS system is automatically initiated in the event of a LOCA. When operating in conjunction with other ECCS, the CS system is required to provide adequate core cooling for all LOCA events. There is no change in the reactor pressures at which the CS is required. The CS system sprays water into the reactor vessel after it is depressurized. The primary purpose of the CS system is to provide reactor vessel coolant inventory makeup for a large break LOCA and for any small break LOCA after the reactor vessel has depressurized. It also provides long-term core cooling in the event of a LOCA.

The ECCS performance evaluation demonstrates that the existing CS system performance capability, in conjunction with the other ECCS as required, is adequate to meet the post-LOCA core cooling requirement for the EPU conditions. The licensee stated that **[[**

]] The HCGS CS system is consistent with the **[[ ]]** evaluation in Section 4.1 of ELTR-2.

The licensee further stated that the peak suppression pool temperature (212.3 ^{o}F) during a limiting LOCA exceeds the current maximum operating temperature of 212 ^{o}F for the CS pump seals. As a result, the pump seals were re-qualified to a higher temperature of 218 ^{o}F.

The staff, therefore, accepts the licensee's assessment that EPU does not significantly impact operation of the CS system. Since the licensee's ECCS-LOCA analysis (see section below titled, "ECCS Performance") based on the current CS capability demonstrate that the system provides adequate core cooling, the staff finds the evaluation acceptable, and agree with the licensee's assessment that the CS will continue to meet the NRC's acceptance criteria.

Low Pressure Coolant Injection (LPCI)

The LPCI mode of the RHR system is automatically initiated in the event of a LOCA. The primary purpose of the LPCI mode is to help maintain reactor vessel coolant inventory for a large break LOCA and for any small break LOCA after the reactor vessel has depressurized. The LPCI operating requirements are not affected by EPU. The ECCS performance evaluation demonstrates that the existing LPCI mode performance capability, in conjunction with the other ECCS, is adequate to meet the post-LOCA core cooling requirement for EPU RTP conditions. The licensee stated that **[[**

]] The HCGS RHR LPCI mode is consistent with the generic evaluation provided in Section 4.1 of ELTR-2.

Since the licensee's ECCS-LOCA analysis (see section below titled, "ECCS Performance") based on the current LPCI capability demonstrate that the system provides adequate core cooling, the staff finds the evaluation acceptable, and agree with the licensee's assessment that the LPCI will continue to meet the NRC's acceptance criteria.

Automatic Depressurization System (ADS)

The ADS evaluation scope is provided in Section 5.6.8 of ELTR-1. The ADS uses a number of the SRVs to reduce the reactor pressure following a small break LOCA when it is assumed that the high-pressure systems have failed. After a specified delay, the ADS actuates either on low water level plus high drywell pressure or on sustained low water level alone. This allows the CS and LPCI to inject coolant into the reactor vessel. Plant design requires a minimum flow capacity for the SRVs, and that ADS initiates following confirmatory signals and associated time delays. The required flow capacity and ability to initiate ADS on appropriate signals are not affected by EPU. The ADS initiation logic and ADS valve control are not affected, and are adequate for EPU conditions. The licensee stated that **[[**

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Since the licensee's ECCS-LOCA analysis (see section below titled, "ECCS Performance"), based on the current ADS capability, demonstrates that the system provides adequate core cooling, the staff finds the evaluation acceptable, and agree with the licensee's assessment that the ADS will continue to meet the NRC's acceptance criteria.

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

ECCS Performance

The ECCS is designed to provide protection against 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 10 CFR Part 50, Appendix K. The following staff-approved codes were used for the equilibrium core LOCA analysis:

SAFER

The SAFER code was used to calculate the long-term-thermal-hydraulic behavior of the coolant in the vessel during a LOCA. Some important parameters calculated by SAFER are vessel pressure, vessel water level, and ECCS flow rates. The SAFER code also calculates PCT and local maximum oxidation.

LAMB

The LAMB code is used to analyze the short-term thermal-hydraulic behavior of the coolant in the vessel during a postulated LOCA. In particular, LAMB predicts the core flow, core inlet enthalpy, and core pressure during the initial phase of the LOCA event (i.e. the first 5 seconds)

GESTR

The GESTR code is used to provide best-estimate predictions of the thermal performance of GE nuclear fuel rods experiencing variable power histories. For LOCA analysis, the GESTR code is used to initialize the fuel stored energy and fuel rod fission gas inventory at the onset of a postulated LOCA.

TASC

The TASC code has been accepted for transient analysis and LOCA analysis. TASC is a functional replacement of the SCAT code. TASC is an improved version of the NRC-approved SCAT code, with the added capability to model advanced fuel features (partial length rods and new critical power correlation). TASC is a detailed model of an isolated fuel channel. It is used to predict the time to boiling transition for a large-break LOCA. This value is used in subsequent codes to turn off nucleate boiling heat transfer models and turn on transition boiling models.

In the EPU approach, the LOCA analysis description is based on a limited number of break analyses (one large break and a spectrum of breaks for the small break analyses) instead of the complete set of break-spectrum analyses.

The EPU approach with limited break analyses is acceptable for the following reasons:

1. The staff evaluations of several requests for stretch power increase and EPU at BWRs have shown **[[**

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2. [[
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3. [[
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4. [[
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5. [[
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6. [[
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7. [[
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The LOCA analysis for EPU[215] builds on the existing SAFER/GESTR LOCA analyses for a plant. The staff evaluations of past EPU at BWRs have shown that the basic break spectrum is not affected by EPU and EPU is expected to have a small effect on the licensing basis PCT. A limited set of analyses needs to be performed to determine the impact of EPU. Because the EPU approach has only a small effect on PCT, the limiting single failure will not change for EPU conditions in a plant. The licensing basis PCT is based on the Appendix K PCT. The effect of EPU on the licensing basis PCT will be based on the delta PCT change from the large break and small break evaluation such that the licensing basis PCT is maximized. Use of the most limiting of the nominal or Appendix K PCT changes for the licensing basis PCT will ensure continued compliance with the requirements for the SAFER/GESTR LOCA application methodology as approved by the NRC.

The Licensing Basis PCT is determined based on the calculated nominal PCT with an adder to account for uncertainties. The adder is derived from calculations that are in conformance with the requirements of 10 CFR 50, Appendix K.

Based on the licensee's calculations using EPU equilibrium core for HCGS, the EPU Licensing Basis PCT for both the GE14 and SVEA fuel is due to the DBA (Recirculation Suction Line) large break LOCA with battery failure (limiting single failure). This is unchanged from the current CLTP Licensing Basis PCT. The corresponding break size for the DBA large break is 4.085 ft^2. For EPU (115 percent of CLTP), the Licensing Basis PCT for GE14 fuel is 1380°F at MELLLA conditions (94.8 percent of rated core flow). The comparable Licensing Basis PCT for the CLTP conditions is 1370°F at MELLLA condition (76.6 percent of rated core flow). The Licensing Basis PCT for the SVEA fuel is 1540°F at both CLTP and EPU power, and is based on MELLLA condition (76.6 percent of rated core flow). The calculated results show significant margin to the licensing limit of 2200°F.

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[215] GE Nuclear Energy, "SAFER/GESTER-LOCA Loss of Coolant Accident Analysis for Hope Creek Generating Station at Power Uprate," NEDC-33172P, Class III (proprietary), March 2005 ADAMS Accession No. ML053250469

As stated earlier, the CLTP core at HCGS consists of GE and SVEA-96+ fuel types. For the first EPU core (Cycle 15), there will be predominantly GE14 fuel with some remaining average thrice burned legacy fuel (SVEA-96+). In response to the staff's RAI, by letter dated March 13, 2007, the licensee stated that the SVEA fuel operating in the Cycle 15 core will be high exposure, low reactivity fuel in its fourth or fifth operating cycle. The SVEA peak bundle power will be significantly lower than that of the limiting GE14 fuel. It was stated that based on this lower power, the results of the Cycle 15 EPU core design demonstrate that the GE14 fuel is limiting for MAPLHGR (which protects PCT) for the entire operating cycle. In response to the staff's RAI, by letter dated March 30, 2007, the licensee further stated that the limiting GE14 fuel will be operating at peak exposure values consistent with the maximum (or near maximum) LHGR limit, and therefore consistent with the limiting (or near limiting) PCT, during Cycle 15. Therefore, it is expected that the SVEA PCT will be bounded by the GE14 PCT for operating cycle 15. This will be confirmed by the licensee for the cycle-specific core, and the results are documented in the SRLR for the cycle. The staff finds this acceptable.

In addition to the large break LOCA analysis, the small break LOCA response was reanalyzed using a sufficient number of break sizes in order to assure adequate ADS capacity. The licensee stated that the plant-specific analyses demonstrate the adequacy of the ADS performance at EPU conditions, and that small break LOCA event mitigation is acceptable.

For Single Recirculation Loop Operation (SLO), a multiplier is applied to the Two-Loop Operation LHGR and MAPLHGR limits. Application of the appropriate LHGR/MAPLHGR multiplier for SLO operation assures the expected SLO PCT is less than the calculated PCT for Two-Loop Operation.

The EPU will make a negligible effect on compliance with the other acceptance criteria of 10 CFR 50.46 (local cladding oxidation, core-wide metal-water reaction, coolable geometry). Long term cooling is assured when the core remains flooded to the jet pump top elevation and when a CS system is operating.

Based on licensee's plant-specific LOCA analysis for HCGS EPU condition with equilibrium core, and because the licensee will perform plant cycle-specific evaluations of ECCS-LOCA performance for HCGS first EPU cycle using approved methods, as required in Section 5.2 of ELTR-2, the staff agrees with the licensee that the HCGS ECCS-LOCA performance complies with 10 CFR 50.46 and Appendix K requirements.

As confirmatory evaluations, the staff performed audit calculations. As discussed above, because it is expected that the SVEA PCT will be bounded by the GE14 PCT for the EPU cycles at HCGS, the staff used only GE14 fuel to perform their LOCA audit calculations. The results of the staff's calculations are summarized below:

<u>Audit Calculation</u>

The staff performed audit calculations using the RELAP5 code to assess ECCS performance for the HCGS NSSS. The double-ended recirculation line break was reported by HCGS as the limiting break size. The audit calculation is to confirm that the PCT value reported by the HCGS is reasonable and is under the 2200 °F SL.

RELAP5 model used by the staff for HCGS was based on an existing Browns Ferry RELAP5 model. Both Hope Creak and Browns Ferry reactors are based on GE BWR4 technology. Staff verified that their vessel ID, core equivalent diameter, and core active height are identical. Similar to the Browns Ferry Unit 1, HCGS used GE 14 fuel in their PCT licensing calculation. However, the LPCI flow is not injected into the recirculation line in the HCGS Plant. LPCI flow is injected into the bypass region within the shroud in a manner that is similar to the BWR/5 and BWR/6 plants. Proper modifications were made in the base RELAP5 deck based on the HCGS LPCI configuration. The licensee supplied LPCI flow curves, and those were incorporated into the HCGS RELAP5 model. The NRC RELAP5 model for HCGS included a core model with the average core and hot bundle regions separately using 24 axial cells. The power shapes in the fuel were kept same for the average core, hot bundles, and hot rods. The hot bundle power used was the licensee supplied value, which produced the limiting MCPR. The hot rod power is calculated based on the local peaking factor supplied by the licensee. With the power shape and hot rod power, the PLHGR of the hot rod were obtained at a **[[**

]]. The analysis was performed at the total core power of 3917 MWt (1.02 x 3840 MWt) and a local peaking factor of **[[ ]]** in the hot rod.

Staff audit calculations were preformed using Appendix K assumptions for the large break loss of coolant break analyses. The staff results were then compared to the licensee Appendix K analysis results. HCGS reported that the limiting PCT obtained from small break LOCA analysis with GE 14 fuel and five ADS valves available is at a value of **[[ ]]**, which is more than **[[**
]] obtained by HCGS. Considering this limiting value is much smaller than the acceptable Licensing Basis PCT value at 2200 °F, no small beak LOCA was performed by the NRC staff.

Limiting PCT

Staff performed a double-ended suction recirculation line break LOCA analysis, a DBA with Appendix K assumptions, using the RELAP5 code. The limiting failure for the suction line break LOCA consisted of a battery failure. For a suction line break, this leaves three LPCI pumps, one LPCS pump, and the ADS available. The staff calculation showed that the limiting PCT is 1640 °F. The limiting PCT result of NRC audit calculations is higher than the HCGS PCT prediction. For GE 14 fuel, HCGS obtained a PCT value of **[[ ]]**. The higher PCT for NRC audit calculation was as a result of conservatism assumed in the analysis, and modeling uncertainties. For example, the NRC HCGS model used uniformed fuel length by averaging full length rods and partial length rods. One of the primary reasons for higher PCT is the fact that NRC RELAP5 model did not use the thermal radiation model for the sake of modeling simplification. Without thermal radiation heat transfer from the hot rod to its surroundings, such as water rods and fuel channel wall, it can contribute to higher PCT. But even with this conservative model simplification, the PCT obtained from NRC audit calculation have more than 550 °F safety margin. Therefore, the licensee's conclusion that the HCGS EPU Licensing Basis PCT under the acceptance criteria of 2200°F has been independently confirmed by NRC audit calculation, and therefore, it is acceptable.

Break Size Sensitivity Study

The staff also performed LOCA sensitivity study with smaller break sizes on the recirculation line. For a break at 80 percent of DBA break size, a PCT value of 1553 °F was obtained. For a break at 60 percent of DBA break size, a PCT value of 1527 °F was obtained. These values were compared to HCGS calculation results, which were at a value of **[[ ]]**, respectively. Even though NRC audit calculation obtained higher PCT values due to the model simplicity, which was discussed above, the trend of decreasing PCTs with decreasing break size for large break LOCA is similar to that of the licensee's calculation. Therefore, this sensitivity study supported the conclusion by the licensee that the limiting break is at the size of the double-ended recirculation pipe.

Both the licensee's and the staff's calculations demonstrated that for the EPU the peak clad temperatures will comply with the requirements of 10 CFR 50.46.

Conclusion

The NRC staff has reviewed the licensee's analyses of the LOCA events and the ECCS. The NRC staff concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and that the analyses 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, and 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 GDCs 4, 27, 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 Scrams

Regulatory Evaluation

ATWS is defined as an AOO followed by the failure of the reactor portion of the protection system specified in GDC-20. The regulation in 10 CFR 50.62 requires that:

- Each BWR 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 have a SLCS with the capability of injecting into the reactor vessel 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 ID reactor vessel. The system initiation must be automatic.
- Each BWR have equipment to trip the reactor coolant recirculation pumps automatically under conditions indicative of an ATWS.

The NRC staff's review was conducted 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 SLCS operability is not affected by the proposed EPU; and (3) operator actions specified in the plant's EOPs are consistent with the generic emergency procedure guidelines/severe accident guidelines (EPGs/SAGs), 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 Service Level C limit of 1500 psig; (2) the peak clad temperature 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. Review guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

An ATWS event starts when an AOO occurs and yet the control rods could not be inserted to scram the reactor. Due to strong reactivity feedback, reactor power and pressure rise rapidly to reach maximum values and challenge the RCPB and thermal design limits. Eventually the SLCS will inject boron solution into the core after first SRV opens to relieve reactor pressure. It brings the reactor to subcritical state from the hot full power and remains subcritical until the reactor cools down to the cold-shutdown condition.

For every reload, the licensee evaluates how plant modifications, reload core designs, changes in fuel design, and other reactor operating changes that affect the ATWS analysis.
The licensee stated in the PUSAR 9.3 that Hope Creek meets 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 gpm; and (3) an automatic ATWS-Recirculating pump trip (RPT) has been installed.

Section L.3 of ELTR1 discusses the ATWS analyses and provides a **[[** **]]** for the following limiting ATWS events in terms of overpressure and suppression pool cooling: (1) MSIV closure (MSIVC); (2) pressure regulator failure to open (PRFO); (3) LOOP; and (4) inadvertent opening of a relief valve (IORV). Following the ELTR1 guidelines, the licensee performed plant specific EPU GE14 equilibrium core ATWS analyses using ODYN code. The analyses show the most limiting event to be the PRFO event and the results are shown in PUSAR Table 9-9.

The input parameters for Hope Creek ATWS also follow the guidelines in ELTR1 L3. According to PUSAR Table 9-8, the SRV capacity and HP ATWS-RPT set point are not changed. The number of SRV out-of-service remains the same for CLTP condition and EPU condition, and the decay heat models follow the 1979 ANS results. Hence, the input parameters for the analysis are acceptable.

As to operator actions in ATWS, Hope Creek ATWS mitigation strategy is based on the BWROG Emergency Procedure and Severe Accident Guidelines (EPG/SAGs), Revision 1, July 1997. The EOPs are being revised for EPU implementation and will be upgraded to the BWROG EPGs/SAGs Rev. 2. The EOP includes reactor water level reduction below the FW sparger and immediate boron injection for reactor power level above 4 percent. The EPU implementation does not change operator strategy on ATWS level reduction or boron injection. However, EPU does lower the Boron Injection Initiation Temperature (BIIT) about 10 °F (from 150 °F to 140 °F) at Hope Creek for power level below 4 percent due to greater decay heat in EPU. That is, before suppression pool reaches BIIT, boron is injected. When reactor power is above 4 percent power in an EPU ATWS event, there is no change and boron is injected immediately.

In the analysis, the automatic ATWS-RPT trips the recirculation pumps automatically at the pressure set point of 1101 psig. Hope Creek SLCS is designed to start automatically at 230 seconds after ATWS-RPT actuation. According to the sequence events provided in RAI response,[216] the early manual SLCS initiation is evaluated for MSIVC and PRFO events before 230 seconds because SLCS pump discharge relief valve set point is lower than the reactor pressure response. But, the born effects are included in the analysis at 230 seconds to ensure conservatism comparable to the automatic initiation. Also, the FW reduction is included to maintain the water level above top of active core, which is shown in the sequence of events in the RAI response. Since the peak suppression pool temperature can be maintained under the limit, the performance of RHR is proven. Hence, the operator actions are considered in the analysis and the results are acceptable as the follows.

Table 9-9 lists the key results of ATWS analysis:

> Peak vessel bottom pressure 1437 psig < 1500 psig (ASME Service level C)
> Peak cladding temperature 1446 ^{o}F < 2200 ^{o}F (10 CFR 50.46)
> Peak suppression pool temperature 199 ^{o}F < 201 ^{o}F
> Peak containment pressure 9.1 psig < 62 psig
> Local cladding oxidation < 17 percent. (10 CFR 50.46)

The above results show the acceptance criteria are satisfied.

Compared to CLTP results, all major parameters show higher values at EPU condition except the PCT, a lower value (1446 ^{o}F vs 1589 ^{o}F). A further investigation shows that same conservative initial CPR (lower than Operating Limit Minimum CPR) was used for both analysis. Using a lower initial CPR requires a higher bundle power, which is conservative for PCT calculation. The resulting PCT value becomes independent of the core loading conditions for subsequent fuel cycles as a very conservative initial CPR is assumed. This is to ensure the fuel integrity can be maintained during ATWS process for both CLTP and EPU condition. This high bundle power initial condition causes the power-to-flow ratio in hot channel to be lower for EPU because the EPU rated power is higher and radial power distribution is flatter (radial peaking factor is lower). Thus the rods in hot channel experience less severe dryout and produce a lower PCT. Another factor contributing to the lower PCT is the axial power profile. In EPU, bundle powers are higher and thus the axial power is generally less top peaked to meet the thermal limit. Usually top peaked axial power shape results in higher PCT. Thus, the axial shape also contributes to a lower PCT in EPU case.

Based on above evaluation, the staff accepts the ATWS event based on the following facts: (1) Hope Creek meets ATWS mitigation requirements; (2) the ATWS analysis at EPU condition are based on NRC-approved methods; (3) the results meet the acceptance criterion defined at 10 CFR 50.62; and (4) the EPU implementation has sound operator strategy on ATWS level reduction or early boron injection in the EOP with the BWROG EPGs/SAGs strategy.

The ATWS with core instability event occurs at natural circulation following a RPT. EPU allows plants to increase their operating thermal power but does not allow an increase in control rod line. The core design necessary to achieve EPU operations may affect the susceptibility to

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[216] ADAMS Accession No. ML070790508

coupled thermal-hydraulic/neutronic core oscillations at the natural circulation condition because the higher enriched fuel will result in a higher void coefficient which produces higher power change for changes in void content during ATWS. However, it would not significantly affect the event progression since both CLTP and EPU analysis follow same rod line - the MELLLA boundary. **[[**

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The limiting ATWS core instability analysis documented in NEDC-33066[217] was performed for an assumed plant initially operating at CLTP and the MELLLA minimum flow point. **[[**

.]] The void reactivity coefficient, fuel response time (fuel rod diameter), and pressure loss coefficients are the parameters important to determining the overall reactor stability. According to the conclusion of NRC SER associated with NEDC-32164,[218] the analyzed operator actions would effectively mitigate an ATWS instability event. These operator actions will be the same in EPU condition at Hope Creek.

Based on the review, the staff concludes that the ATWS with instability event is acceptable based on the facts: (1) the **[[**

]] and (2) the **[[**

]].

Conclusion

The NRC staff has reviewed the information submitted by the licensee related to ATWS and concludes that the licensee has adequately accounted for the effects of the proposed EPU on ATWS. The NRC staff concludes that the licensee has demonstrated that 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 EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to ATWS.

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

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[217] Hope Creek Generating Station APRM/RBM/Technical Specifications/Maximum Extended Load Line Limit Analysis (ARTS/MELLLA)," NEDC-33066P, Revision 2, February 2005 ADAMS Accession No. ML052030315
[218] GE Nuclear Energy, "Mitigation of BWR Core Thermal-Hydraulics Instabilities in ATWS," NEDO-32164, December 1992

facilities. The NRC's acceptance criteria are based on GDC-62, insofar as it requires the prevention of criticality in fuel storage systems by physical systems or processes, preferably utilizing geometrically safe configurations. Specific review criteria are contained in SRP Section 9.1.1.

Technical Evaluation

The licensee has performed a conservative evaluation to assess the impact of EPU on HCGS fuel pool storage. On the basis of this assessment, the licensee has determined that for EPU, HCGS 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.

The parameter that is used to assure compliance to fuel pool storage rack criteria is lattice k-infinity. The limiting infinite lattice k-infinity for GE/GNF fuel, as prescribed in GESTAR-II is <1.30. For the analysis performed by GE/GNF, the standard process is to determine a "limiting lattice" to bound the performance of the fuel storage unit. This "limiting" or "design basis lattice" is used to determine the maximum reactivity that is allowable in the fuel storage unit of interest.

Based on the NRC staff's review of the licensee's generic evaluation and rationale, 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 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 has 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. Specific review criteria are contained in SRP Section 9.1.2.

Technical Evaluation

As discussed in the previous section, the licensee has performed conservative evaluation to assess the impact of EPU on HCGS fuel pool storage. On the basis of this assessment, the licensee has determined that for EPU, HCGS is bounded by the requirements of current licensing basis, and that there is no need to change the licensing basis requirements for the spent fuel storage.

The parameter that is used to assure compliance to fuel pool storage rack criteria is lattice k-infinity. The limiting infinite lattice k-infinity for GE/GNF fuel as prescribed in GESTAR-II is <1.30. For the analysis performed by GE/GNF, the standard process is to determine a "limiting lattice" to bound the performance of the fuel storage unit. This "limiting" or "design basis lattice" is used to determine the maximum reactivity that is allowable in the fuel storage unit of interest.

The licensee stated that the GNF 10x10 lattice that is used for this purpose is a lattice that is uniformly loaded with the maximum available enrichment and has a minimal loading of low concentration of gadolinium (Gd). The specific "GE14 design basis" lattice for the GNF HCGS fuel storage analysis was **[[ ]]**, which bounds fuel designs for both CLTP and EPU conditions. This "design basis lattice" was depleted to determine the point of maximum in-core cold reactivity.

The licensee stated that by use of a limiting "design basis lattice" at peak reactivity, the possibility of a full core off-load at peak lattice reactivity is accommodated without special analysis and the complete range of potential lattice designs and operational strategies are shown to be acceptable. As a result of the characteristic of Gd to deplete most rapidly in a low in-channel void condition, the effects of EPU/MELLLA operation do not impact the maximum cold lattice reactivity.

It was indicated by the licensee that analyses have also been performed for the legacy SVEA fuel, demonstrating the acceptability of storing SVEA fuel in the HCGS fuel pool racks. Since no new SVEA fuel will be introduced for EPU, and the remaining SVEA fuel in the reactor core is operating at exposure values significantly past the point of peak reactivity, EPU operation will not adversely impact the existing fuel pool criticality analysis for SVEA fuel.

The licensee further stated that the SFP system is located in the reinforced concrete RB. 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 generic evaluation and rationale, 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. The 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 has reviewed the licensee's analyses related to the effects of the proposed EPU on the spent fuel storage capability and concludes that the licensee has 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 Additional Review Area - Methods Evaluation

Regulatory Evaluation

The NRC staff acceptance criteria were based on the following GDC in 10 CFR 50 Appendix A:

1. GDC 10, “Reactor Design,” requiring the reactor design (reactor core, RCS, control and protection systems) to assure that SAFDL are not exceeded during any condition of normal operation, including AOOs.
2. GDC 11, “Reactor Inherent Protection,” requiring a net negative prompt feedback coefficient in the power operating range.
3. GDC 12, “Suppression of Reactor Power Oscillations,” requiring that power oscillations that can result in conditions exceeding SAFDL are not possible, or can be reliably and readily detected and suppressed.
4. GDC 26, “Reactivity Control System Redundancy and Capability,” requiring, in part, a reactivity control system capable of holding the reactor subcritical under cold conditions.
5. GDC 27, “Combined Reactivity Control Systems Capability,” requiring, in part, a control system designed to control reactivity changes during accident conditions in conjunction with poison addition by the ECCS.

Technical Evaluation

Application of NEDC-33173P to GE14 for HCGS EPU Cycle 15

The analyses supporting safe operation at EPU conditions are performed using NRC-approved licensing methodology, analytical methods and codes. In general, the accuracy of the analytical methods and codes are assessed and benchmarked against measurement data, comparisons to actual nuclear plant test data and research reactor measurement data. The uncertainties and biases associated with specific correlations simulating physical phenomena, with key parameters or with integral code calculations modeling a design bases event are determined. The identified uncertainties associated with the analytical methods, the measured quantities used to simulate the core conditions and the manufacturing tolerances (e.g., fuel manufacturing tolerances) are accounted for in the analyses. NRC-approved licensing methodology, topical reports and codes specify the applicability ranges.

The generic LTR covering specific analytical methods or code system quantify the accuracy of the methods or the code used. The SE report approving the topical report includes limitations that delineate the conditions that warrant specific actions, such as obtaining measurement data or when new NRC approval is required. In general, the use of NRC-approved analytical methods is contingent upon application of these methods and codes within the ranges for which the data was provided and against which the methods were evaluated. Thus, in general, the plant-specific application does not entail review of the NRC-approved analytical methods and codes.

The NRC staff review of NEDC-33173P was to verify the following:

1. The analytical methods and codes used to perform the design-bases safety analyses will be applied within the applicable NRC-approved validation ranges. The calculation and measurement uncertainties applied to the thermal limit calculations and the models simulating physical phenomena will remain valid for the predicted neutronic and thermal-hydraulic core and fuel conditions during steady-state, transient, and accident conditions. The qualification database supporting analytical models simulating physical phenomena remains valid and applicable to the conditions under which it is applied, including those models and key parameters in which specific uncertainties are not applied.

2. If the NRC-approved analytical methods and codes are extended outside the applicability ranges, the extension of the specific models are demonstrated to be acceptable or additional margins are applied to the affected downstream safety analyses until such time the supporting qualification data is extended.

The NRC staff SER for NEDC-33173P, "Applicability of GE Methods to Expanded Operating Domains," dated January 17, 2008, [219] specifies the limitations that apply to NEDC-33173P.

PSEG referenced NEDC-33173P to justify application of GE methods to HCGS EPU. Each limitation specified in the NRC staff SE for NEDC-33173P was evaluated for acceptability for HCGS EPU. In addition, the NRC staff evaluation of applicability of NEDC-33173P, specifically to GE14 for HCGS Cycle 15, is discussed.

Limitation #1 TGBLA/PANAC Version

The neutronic methods used to simulate the reactor core response and that feed into the downstream safety analyses supporting operation at EPU/MELLLA+ will apply TGBLA06/PANAC11 or later NRC-approved version of neutronic method. Per response to RAI 3.8,[220] HCGS will apply TGBLA06/PANAC11 for EPU. Therefore, HCGS is required to comply with this limitation.

Limitation #2 3D Monicore

For EPU/MELLLA+ applications, relying on TGBLA04/PANAC10 methods, the bundle RMS difference uncertainty will be established from plant-specific core-tracking data, based on TGBLA04/PANAC10. The use of plant-specific trendline based on the neutronic method employed will capture the actual bundle power uncertainty of the core monitoring system. Per response to RAI 3.8, TGBLA06/PANAC11 was used to support the HCGS EPU application. Therefore, this limitation is not applicable to the current amendment request.

Limitation #3 Power-to-Flow Ratio

Plant-specific EPU and expanded operating domain applications will confirm that the core thermal power to total core flow ratio will not exceed 50 MWt/Mlbm/hr at the low flow point at

[219] ADAMS Accession No. ML073340231
[220] ADAMS Accession No. ML071360375

rated power. For plants that exceed the power-to-flow value of 50 MWt/Mlbm/hr, the application will provide power distribution assessment to establish that neutronic methods axial and nodal power distribution uncertainties have not increased. HCGS power-to-flow ratio corresponding to minimum allowable core flow at EPU power level is approximately 40.5 MWt/Mlbm/hr. Therefore, HCGS complies with this limitation.

Limitation #4 SLMCPR 1

For EPU operation, a 0.02 value shall be added to the cycle-specific SLMCPR value. This adder is applicable to SLO, which is derived from the dual loop SLMCPR value. Per response to RAI 3.8, HCGS will incorporate the additional 0.02 margin for EPU cycles. Therefore, HCGS is required to comply with this limitation.

Limitation #5 SLMCPR 2

For operation at MELLLA+, including operation at the EPU power levels at the achievable core flow statepoint, a 0.03 will be added to the cycle-specific SLMCPR value. Due to instability concerns, SLO is not allowed for operation at MELLLA+. Per response to RAI 3.8, HCGS is not implementing MELLLA+. Therefore, this limitation is not applicable to the current amendment request.

Limitation #6 R-factor

The plant specific R-factor calculation at a bundle level will be consistent with lattice axial void conditions expected for the hot channel operating state. The plant-specific EPU/MELLLA+ application will confirm that the R-factor calculation is consistent with the hot channel axial void conditions. Per response to RAI 3.8,[221] HCGS will use R-factor calculations consistent with the predicted axial void conditions for EPU cycles. Therefore, HCGS is required to comply with this limitation.

Limitation #7 ECCS-LOCA 1

For applications requesting implementation of EPU or expanded operating domains, including MELLLA+, the small and large break ECCS-LOCA analyses will include top-peaked and mid-peaked power shape in establishing the MAPLHGR and determining the PCT. This limitation is applicable to both the licensing bases PCT and the upper bound PCT. The plant-specific applications will report the limiting small and large break licensing basis and upper bound PCTs. Per response to RAI 3.8, HCGS will provide the limiting GE14 LOCA analysis at EPU conditions using top-peaked axial power shape. Therefore, HCGS is required to comply with this limitation.

Limitation #8 ECCS-LOCA 2

The ECCS-LOCA will be performed for all statepoints in the upper boundary of the expanded operating domains, including the minimum core flow statepoints, the transition statepoint as defined in the licensee's application and the 55 percent core flow statepoint. The plant-specific application will report the limiting ECCS-LOCA results as well as the rated power and flow results. The SRLR will include both the limiting statepoint ECCS-LOCA results and the rated conditions ECCS-LOCA results. Per response to RAI 3.8, HCGS is not implementing

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[221] ADAMS Accession No. ML071360375

MELLLA+. Therefore, this limitation is not applicable to the current amendment request.

Limitation #9 Transient LHGR 1

Plant-specific EPU and MELLLA+ applications will demonstrate and document that during normal operation and core-wide AOOs, the thermal-mechanical (T-M) acceptance criteria as specified in Amendment 22 to GESTAR II will be met. Specifically, during an AOO, the licensing application will demonstrate that the: (1) loss of fuel rod mechanical integrity will not occur due to fuel melting; and (2) loss of fuel rod mechanical integrity will not occur due to pellet–cladding mechanical interaction. The plant-specific application will demonstrate that the T-M acceptance criteria are met for both the UO2 and the limiting GdO2 rods. Per response to RAI 3.8, HCGS demonstrated a 13 percent margin to fuel melt criterion and a 22 percent margin to the pellet cladding mechanical interaction (PCMI) criterion for the most limiting rod. Therefore, HCGS complies with this limitation.

Limitation #10 Transient LHGR 2

Each EPU and MELLLA+ fuel reload will document the calculation results of the analyses demonstrating compliance to transient T-M acceptance criteria. The plant T-M response will be provided with the SRLR or COLR, or it will be reported directly to the NRC as an attachment to the SRLR or COLR. Per response to RAI 3.8, HCGS is required to confirm that its initial EPU cycle complies with the transient thermal-mechanical acceptance criteria. Therefore, HCGS complies with this limitation.

Limitation #11 Transient LHGR 3

To account for the impact of the void history bias, plant-specific EPU and MELLLA+ applications using either TRACG or ODYN will demonstrate an equivalent to 10 percent margin to the fuel centerline melt and that the 1 percent cladding circumferential plastic strain acceptance criteria due to pellet-cladding mechanical interaction for all of limiting AOO transient events, including equipment out-of-service. Limiting transients in this case, refers to transients where the void reactivity coefficient plays a significant role (such as pressurization events). If the void history bias is incorporated into the coupled neutronic and transient code set, then the additional 10 percent margin to the fuel centerline melt and the 1 percent cladding strain is no longer required. Per response to RAI 3.8,[222] HCGS demonstrated a 13 percent margin to fuel melt criterion and a 22 percent margin to the PCMI criterion for the most limiting rod. Therefore, HCGS complies with this limitation.

Limitation #12 Application of 10 Weight Percent Gadolinium (Gd)

Before applying 10 weight percent Gd to licensing applications, including EPU and expanded operating domain, the NRC staff needs to review and approve the T-M LTR demonstrating that the T-M acceptance criteria specified in GESTAR II and Amendment 22 to GESTAR II can be met for steady-state and transient conditions. Specifically, the T-M application must demonstrate that the T-M acceptance criteria can be met for thermal overpower protection (TOP) and mechanical overpower procedure (MOP) conditions that bounds the response of plants operating at EPU and expanded operating domains at the most limiting statepoints, considering the operating flexibilities (e.g., equipment out-of-service).

[222] ADAMS Accession No. ML071360375

Before the use of 10 weight percent Gd for modern fuel designs, NRC must review and approve TGBLA06 qualification submittal. Where a fuel design refers to a design with Gd-bearing rods adjacent to vanished or water rods, the submittal should include specific information regarding acceptance criteria for the qualification and address any downstream impacts in terms of the safety analysis. The 10 weight percent Gd qualifications submittal can supplement this report. Per response to RAI 3.8, HCGS's initial EPU cycle does not use gadolinia greater than 6.0 weight percent. Therefore this limitation is not applicable to the current amendment request.

Limitation #13 Part 21 Evaluation of GSTR-M Fuel Temperature Calculation

Any conclusions drawn from the NRC staff evaluation of the GE's Part 21 report will be applicable to the GSTR-M T-M assessment of this SE for future license application. GE submitted the T-M Part 21 evaluation, which is currently under NRC staff review. Upon completion of its review, NRC staff will inform GE of its conclusions. At the time drafting of the current SE, the impact of the GSTR-M thermal-mechanical methodology was still under NRC staff evaluation. Therefore, this limitation is not applicable to the current amendment request. However based on the outcome of the NRC staff evaluation and its safety significance, PSEG is expected to address the applicability of the thermal-mechanical methodology for EPU operation.

Limitation #14 LHGR and Exposure Qualification

In MFN 06-481, GE committed to submit plenum fission gas and fuel exposure gamma scans as part of the revision to the T-M licensing process. The conclusions of the plenum fission gas and fuel exposure gamma scans of GE 10x10 fuel designs as operated will be submitted for NRC staff review and approval. This revision will be accomplished through Amendment to GESTAR II or in a T-M licensing LTR. PRIME (FLN-2007-001) has been submitted to the staff for review. Once the PRIME LTR and its application are approved, future license applications for EPU and MELLLA+ referencing LTR NEDC-33173P must utilize the PRIME T-M methods. This limitation applies to future EPU applications. Therefore, this limitation is not applicable to the current amendment request.

Limitation #15 Void Reactivity 1

The void reactivity coefficient bias and uncertainties in TRACG for EPU and MELLLA+ must be representative of the lattice designs of the fuel loaded in the core. EPU transient analyses for HCGS are based on the ODYN methodology. Therefore, this limitation is not applicable to the current amendment request.

Limitation #16 Void Reactivity 2

A supplement to TRACG /PANAC11 for AOO is under NRC staff review.[223] TRACG internally models the response surface for the void coefficient biases and uncertainties for known dependencies due to the relative moderator density and exposure on nodal basis. Therefore, the void history bias determined through the methods review can be incorporated into the response surface "known" bias or through changes in lattice physics/core simulator methods for establishing the instantaneous cross-sections. Including the bias in the calculations negates the

[223] GE Nuclear Energy, "Generic Electric Standard Application for Reactor Fuels, "NEDE-24011-P-A and NEDE-24011-P-A-US," (latest approved version)(Known as GESTAR-II) (ADAMS Accession No. ML011230175).

need for ensuring that plant-specific applications showing sufficient margin (see limitation 11). For application of TRACG to EPU and MELLLA+ applications, the TRACG methodology must incorporate the void history bias. The manner in which this void history bias is accounted for will be established by the NRC staff SE approving NEDE-32906P, Supplement 3, "Migration to TRACG04/PANAC11 from TRACG02/PANAC10," May 2006. This limitation applies until the new TRACG/PANAC methodology is approved by the NRC staff. EPU transient analyses for HCGS are based on the ODYN methodology. Therefore, this limitation is not applicable to the current amendment request.

Limitation #17 Steady-State 5 Percent Bypass Voiding

The instrumentation specification design bases limits the presence of bypass voiding to 5 percent (LRPM levels). Limiting the bypass voiding to less than 5 percent for long-term steady operation ensures that instrumentation is operated within the specification. For EPU and MELLLA+ operation, the bypass voiding will be evaluated on a cycle-specific basis to confirm that the VF remains below 5 percent at all LPRM levels when operating at steady-state conditions within the MELLLA+ upper boundary. The highest calculated bypass voiding at any LPRM level will be provided with the plant-specific SRLR. Per response to RAI 3.8,[224] HCGS will confirm that the bypass voiding for HCGS's initial EPU cycle will to be below 5 percent. Therefore, HCGS is required to comply with this limitation.

Limitation #18 Stability Setpoints Adjustment

The NRC staff concludes that the presence bypass voiding at the low-flow conditions where instabilities are likely can result in calibration errors of less than 5 percent for OPRM cells and less than 2 percent for APRM signals. These calibration errors must be accounted for while determining the setpoints for any detect and suppress long term methodology. The calibration values for the different long-term solutions are specified in the associated sections of this SER, discussing the stability methodology. Per response to RAI 3.8,[225] HCGS EPU reload analysis will account for the calibration errors due to bypass voiding when determining the stability detect and suppress setpoints. Therefore, HCGS is required to comply with this limitation.

Limitation #19 Void-Quality Correlation 1

For applications involving PANCEA/ODYN/ISCOR/TASC for operation at EPU and MELLLA+, an additional 0.01 will be added to the OLMCPR, until such time that GE expands the experimental database supporting the Findlay-Dix void-quality correlation to demonstrate the accuracy and performance of the void-quality correlation based on experimental data representative of the current fuel designs and operating conditions during steady-state, transient, and accident conditions. Per response to RAI 3.8, HCGS will incorporate the additional 0.01 margin to OLMCPR for EPU cycles. Therefore, HCGS is required to comply with this limitation.

Limitation #20 Void-Quality Correlation 2

The NRC staff is currently reviewing Supplement 3 to NEDE-32906P, "Migration to TRACG04/PANAC11 from TRACG02/PANAC10," dated May 2006. The adequacy of the

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[224] ADAMS Accession No. ML071360375
[225] ADAMS Accession No. ML071360375

TRACG interfacial shear model qualification for application to EPU and MELLLA+ will be addressed under this review. Any conclusions specified in the NRC staff SE approving Supplement 3 to LTR NEDC-32906P[226] will be applicable as approved to plants that use TRACG04/PANAC11. EPU transient analyses for HCGS are based on the ODYN methodology. Therefore, this limitation is not applicable to the current amendment request.

Limitation #21 MELLLA+

LTR NEDC-33006P, Revision 2[227], provides GE safety analysis report for operation at the proposed expanded operating domains. LTR NEDC-33173P[228] provides the bases for accepting the application of GE NRC-approved analytical methods and codes to MELLLA+ high power and low flow conditions. NRC approval of LTR NEDC 33173P does not constitute as acceptance of the implementation of MELLLA+ operation for BWRs. MELLLA+ implementation is contingent upon approval of the LTR NEDC-33006P, Revision 2 and the plant-specific MELLLA+ application. Per response to RAI 3.8, HCGS is not implementing MELLLA+. Therefore, this limitation is not applicable to the current amendment request.

Limitation #22 Mixed Core Method 1

Plants implementing EPU or MELLLA+ with mixed fuel vendor cores will provide plant-specific justification for extension of GE's analytical methods or codes. The content of the plant specific application will cover the topics addressed in this SE as well as subjects relevant to application of GE's methods to legacy fuel. Alternatively, GE may supplement or revise LTR NEDC-33173P[229] for mixed core application. PSEG submitted "Mixed Core Analysis Report (MCAR) for Hope Creek Extended Power Uprate" and "Mixed Core Analysis Report (MCAR) for Hope Creek Reload 12 Cycle 13"[230] providing justification for applying GE methods to the SVEA 96+ fuel. Staff evaluation is provided in the section titled, "Applicability of NEDC-33173P to SVEA 96+ Fuel."

Limitation #23 Mixed Core Method 2

For any plant-specific applications of TGBLA06 with fuel type characteristics not covered in this review, GE needs to provide assessment data similar to that provided for the GE fuels. The Interim Methods review is applicable to all GE lattices up to GE14. Fuel lattice designs, other than GE lattices up to GE14, with the following characteristics are not covered by this review:

- square internal water channels water crosses
- Gd rods simultaneously adjacent to water and vanished rods
- 11x11 lattices
- Mixed Oxide (MOX) fuel

[226] GE Nuclear Energy, "Generic Electric Standard Application for Reactor Fuels, "NEDE-24011-P-A and NEDE-24011-P-A-US," (latest approved version)(Known as GESTAR-II) ADAMS Accession No. ML011230175

[227] GE letter (MFN-05-141) to NRC dated November 28, 2005, Subject: GE Licensing Topical Report NEDC-33006P, Revision 2, "Maximum Extended Load Line Limit Analysis Plus," (TAC No. MB6157) ADAMS Accession No. ML053300526

[228] GE Licensing Topical Report (LTR), NEDC-33173P Revision 1, Applicability of GE Methods to Expanded Operating Domains," February 10, 2006, ADAMS Accession No. ML060450677

[229] GE Licensing Topical Report (LTR), NEDC-33173P, Revision 1, "Applicability of GE Methods to Expanded Operating Domains," February 10, 2006, ADAMS Accession No. ML060450677

[230] ADAMS Accession Nos. ML053190286 and ML053190325, respectively

The acceptability of the modified epithermal slowing down models in TGBLA06 has not been demonstrated for application to these or other geometries for expanded operating domains. Significant changes in the Gd rod optical thickness will require an evaluation of the TGBLA06 radial flux and Gd depletion modeling before being applied. Increases in the lattice Gd loading that result in nodal reactivity biases beyond those previously established will require review before the GE methods may be applied. PSEG submitted “Mixed Core Analysis Report (MCAR) for Hope Creek Extended Power Uprate” and “Mixed Core Analysis Report (MCAR) for Hope Creek Reload 12 Cycle 13” providing justification for applying GE methods to the SVEA 96+ fuel. Staff evaluation is provided in the section titled, “Applicability of NEDC-33173P to SVEA 96+ Fuel.”

Limitation #24 MELLLA+ Eigenvalue Tracking

In the first plant-specific implementation of MELLLA+, the cycle-specific eigenvalue tracking data will be evaluated and submitted to the NRC to establish the performance of nuclear methods under the operation in the new operating domain. The following data will be analyzed:

- Hot critical eigenvalue;
- Cold critical eigenvalue;
- Nodal power distribution (measured and calculated TIP comparison);
- bundle power distribution (measured and calculated TIP comparison);
- Thermal margin;
- Core flow and pressure drop uncertainties; and
- The MCPR Importance Parameter (MIP) Criterion (e.g., determine if core and fuel design selected is expected to produce a plant response outside the prior experience base).

Provision of evaluation of the core-tracking data will provide the NRC staff with bases to establish if operation at the expanded operating domain indicates: (1) changes in the performance of nuclear methods outside the EPU experience base; (2) changes in the available thermal margins; (3) need for changes in the uncertainties and NRC-approved criterion used in the SLMCPR methodology; or (4) any anomaly that may require corrective actions. Per response to RAI 3.8,[231] HCGS is not implementing MELLLA+. Therefore, this limitation is not applicable to the current amendment request.

Limitation #25 Plant-Specific Application

The plant-specific applications will provide prediction of key parameters for cycle exposures for operation at EPU and MELLLA+. The plant-specific prediction of these key parameters will be plotted against the EPU Reference Plant experience base and MELLLA+ operating experience, if available. For evaluation of the margins available in the fuel design limits, plant-specific applications will also provide quarter core map (assuming core symmetry) showing bundle power, bundle operating LHGR, and MCPR for beginning of cycle (BOC), middle of cycle (MOC), and end of cycle (EOC). Since the minimum margins to specific limits may occur at exposures other than the traditional BOC, MOC, and EOC, the data will be provided at these exposures. PSEG submitted the requested parameters for HCGS EPU conditions in “Interim Methods LTR Supplement for Hope Creek Extended Power Uprate.”[232] The parameters were

[231] ADAMS Accession No. ML071360375
[232] ADAMS Accession No. ML062680455

compared against the existing EPU experience base, demonstrating that HCGS EPU will be within the bounds of current EPU experience base. Therefore, HCGS complies with this limitation.

Applicability of NEDC-33173P to GE14 for HCGS Cycle 15

NEDC-33173P has been reviewed for all GE14 lattices described in NEDE-31152P.[233] The specific limitations, conditions, and restrictions as documented in the staff's SER[234] are therefore applicable to the GE14 lattices encompassed by the envelope of lattices detailed in NEDE-31152P. The HCGS EPU MCAR describes the specific GE14 bundles and lattices included in the Reference Loading Pattern (RLP) design. These same lattices were modeled with TGBLA06V and compared with Monte Carlo N. Particle Transport Code (MCNP) in the HCGS Cycle 13 MCAR[235] for the standard void depletion cases as a function of exposure and boron concentration.

The features of the HCGS GE14 lattices that the staff reviewed for applicability include the split nature of the gadolinia loading, and the presence of a low gadolinia loaded fuel pin simultaneously adjacent to a water rod and a vanished rod. Split gadolinia loadings refer to those lattices that have several gadolinia loaded fuel pins where the loading in the pins is not uniform (for example, a lattice that includes gadolinia loaded pins up to both 4 w/o Gd_2O_3 and 8 w/o Gd_2O_3). The staff noted that at the CLTP the comparative analyses performed with TGBLA06V and MCNP demonstrate that the uncertainties and biases are within the uncertainty ranges quoted generically for SLMCPR and maximum linear heat generation ratio (MLHGR) limit determinations.[236]

TGBLA06V is the original production code version for the TGBLA06 methodology and has subsequently been improved. The most recent version, and the approved version for expanded operating domain analyses, is TGBLA06AE5. The improvements include several revisions that enhance the modeling of gadolinia loaded fuel pins, particularly for designs with split gadolinia loadings and gadolinia rods adjacent to vanished rods. The range of the designs evaluated by the staff for NEDC-33173P encompasses the HCGS GE14 lattices in terms of gadolinia loading, number of gadolinia pins, and arrangements of gadolinia pins near non-fuel pins.

TGBLA06 includes a gadolinia pin flux renormalization model. During the lattice physics calculations the model corrects the predicted flux distribution in the gadolinia loaded fuel pins by increasing the flux in the center of the pin based on a normalization of TGBLA06 uncorrected results to MCNP results for a representative set of GE lattices. This correction factor has been applied uniformly to all GE lattices introduced since the original development of the renormalization factor. In TGBLA06AE5 a correction was made to the code which involves the determination of when to deactivate the flux renormalization based on the Gd-155 and Gd-157 (highly absorbing Gd isotopes) remaining in the pin after several depletion steps in the calculation. The nature of the applicability of the generic renormalization factor, and the point in

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[233] GNF Letter FLN-2002-017, to NRC dated November 8, 2002, "NEDE-31152P Supplement 3, General Electric Fuel Bundle Designs," ADAMS Accession No. ML023260462

[234] ADAMS Accession No. ML041980329

[235] 0000-0029-7705-MCAR, Revision 0, "Mixed Core Analysis Report (MCAR) for Hope Creek Reload 12 Cycle 13," April 2005, ADAMS Accession No. ML053190325

[236] 0000-0029-7705-MCAR, Revision 0, "Mixed Core Analysis Report (MCAR) for Hope Creek Reload 12 Cycle 13," April 2005 (ADAMS Accession No. ML053190325 and GE Licensing Topical Report (LTR), NEDC-33173P Revision 1, Applicability of GE Methods to Expanded Operating Domains," February 10, 2006 (ADAMS Accession No. ML060450677)

depletion where the renormalization correction is deactivated are concerns to the staff and warranted review for the HCGS EPU application. TGBLA06AE5 corrects a coding error whereby the renormalization feature was deactivated based on the pin with the lowest remaining concentration of highly absorbing Gd. In TGBLA06AE5 the renormalization is deactivated on a pin-by-pin basis as opposed to the entire lattice, and therefore has an improved predictive capability for split gadolinia loaded lattices.

Review of the lattice information included in the MCARs and Supplement 3 to NEDE-31152[237] show that the HCGS EPU GE14 lattices fall within the range generically reviewed by the staff as documented in NEDC-33107P/NEDO-33107NP.[238] Therefore, the renormalization factor is appropriate for use in lattice physics analyses at EPU conditions. Secondly, the NRC staff notes that these lattices are split gadolinia lattices. Therefore, based on comparative results using TGBLA06V, the staff has reasonable assurance that the use of the TGBLA06AE5 code to perform analyses for the HCGS cycle 15 core simulator and to generate upstream input to safety analyses will show a higher degree of accuracy than that previously demonstrated for HCGS.

Based on above and any commitments made by PSEG to address the limitations in the SE[239] for NEDC-33173P, the NRC staff finds that the NEDC-33173P is applicable to the GE14 fuel in HCGS EPU Cycle 15 and adequate for performing associated analyses at EPU conditions in accordance with the SE and GE Licensing Topical Report (LTR), NEDC-33173P Revision 1, Applicability of GE Methods to Expanded Operating Domains.[240]

The applicability of NEDC-33173P to SVEA 96+ for HCGS Cycle 15 is discussed separately below.

Application of NEDC-33173P to SVEA 96+ for HCGS Cycle 15

The NRC staff review of the nuclear codes in NEDC-33173P for BWR expanded operating domain did not include a review of the capabilities of the nuclear methods to adequately perform licensing analyses for mixed cores (cores with fuel provided by several vendors). Therefore, the NRC staff reviewed the plant and cycle specific information regarding mixed cores to determine the acceptability of the GE proprietary modeling techniques in NEDC-33173P as they relate to demonstrating compliance with the prescribed GDC.

The staff reviewed the information[241] provided by PSEG to determine whether:

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[237] ADAMS Accession Nos. ML053190286, ML053190325, and ML023260462
[238] Safety Evaluation Report by the Office of Nuclear Reactor Regulation Relating to Global Nuclear Fuel – Americas Topical Report NEDC-33107P/NEDO-33107NP “GEXL80 Correlation for SVEA 96+ Fuel.” March 2004, ADAMS Accession No. ML040850144.
[239] Final Safety Evaluation for Global Nuclear Fuel (GNF) Licensing Topical Report NEDC-33107P, "GEXL80 Correlation for SVEA96+ FUEL" (TAC NO. MC0666), dated July 19, 2004, ADAMS Accession No. ML041980329
[240] GE Licensing Topical Report (LTR), NEDC-33173P Revision 1, “Applicability of GE Methods to Expanded Operating Domains," February 10, 2006, ADAMS Accession No. ML060450677
[241] 0000-0031-9433-MCAR, Revision 0, “Mixed Core Analysis Report (MCAR) for Hope Creek Extended Power Uprate,” April 2005 (ADAMS Accession No. ML053190286); 0000-0029-7705-MCAR, Revision 0, “Mixed Core Analysis Report (MCAR) for Hope Creek Reload 12 Cycle 13,” April 2005 (ADAMS Accession No. ML053190325); and 0000-0031-9433-IMLTR-SUP1, Revision 0, “Interim Methods LTR Supplement for Hope Creek Extended Power Update,” July 2006 (ADAMS Accession No. ML062680455).

- GE methods in NEDC-33173P are acceptable to model the SVEA 96+ legacy fuel as operated in HCGS EPU Cycle 15.
- The results of core and cycle specific analyses demonstrate compliance with the prescribed GDC with adequate conservatism to account for uncertainties.

The GE steady state nuclear design methodology produces lattice parameters for downstream use in a core simulator and subsequent transient calculations. The lattice physics methodology is TGBLA06. TGBLA06 is a collision probability lattice transport code that has been previously reviewed by the staff for application to SVEA 96+ lattices for BWRs operating under CLTP normal operating conditions.

The intent of the NRC staff review is to ensure that PSEG has adequately modeled the SVEA 96+ lattices such that uncertainties in parameters affecting thermal margin determinations are within the prescribed ranges set forth in NEDC-33173P.

For the HCGS EPU Cycle 15 specific mixed core analyses, the NRC staff has reviewed the ability of the TGBLA06 methodology to adequately determine SVEA 96+ lattice parameters for downstream analyses. Particularly, the NRC staff review is based on qualification of the methods against MCNP results, the operating conditions of the SVEA 96+ fuel bundles, and consideration of specific models in TGBLA06V and TGBLA06AE5.

In general, collision probability techniques must be corrected to account for the effects of neutron slowing down in large moderating regions of the lattice, for example in regions such as the bypass, water rods, or water crosses. The purpose being the fundamental assumptions in the THERMOS techniques for predicting the cell flux distribution. TGBLA06 includes specific models that artificially enhance the epithermal slowing down power in water rods based on an averaging technique and the size of the water region.

Accurate modeling of slowing down for modern fuel designs is important as it directly affects the ability of any methodology to predict the depletion of burnable poisons and subsequently pin power peaking factors as a function of exposure. The pin power peaking is a key factor in the determination of the bundle R-factor (and hence bundle CPR) as well as the maximum nodal LHGR, both of which must be determined and shown to acceptably meet the requirements of GDC 10.

The SVEA 96+ lattice design differs from standard GE lattice designs in that it includes a large central water cross, as opposed to water rods in GE designs. PSEG has described in 0000-0029-7705-MCAR, Revision 0, "Mixed Core Analysis Report (MCAR) for Hope Creek Reload 12 Cycle 13"[242] (hereinafter referred to as *Cycle 13 MCAR*) the specific assumptions made in the modeling of the SVEA 96+ two dimensional lattice with TGBLA06, as TGBLA06 does not include the capability to directly model the water cross. **[[**

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PSEG's basis for demonstrating adequate performance of TGBLA06 is to compare results of lattice analyses performed with TGBLA06 for the SVEA 96+ lattices against results calculated by MCNP. The particular parameters examined are the lattice infinite eigenvalue and the lattice pin fission density distribution. The former is a key parameter in the calculation of the nodal

[242] 0000-0029-7705-MCAR, Revision 0, "Mixed Core Analysis Report (MCAR) for Hope Creek Reload 12 Cycle 13," April 2005, ADAMS Accession No. ML053190325

power in downstream simulator calculations and the latter is a measure of the accuracy of the code in predicting the two dimensional power distribution and R-factor. The NRC staff evaluated TGBLA06 calculational performance in regards to each figure of merit and the reviews are separately discussed in the following two sections of this report.

Infinite Eigenvalue Results

Figures 2.1 through 2.6 of Cycle 13 MCAR illustrate the differences in lattice eigenvalue between TGBLA06 and MCNP calculations for the unexposed SVEA 96+ lattices. These comparisons indicate excellent agreement between MCNP and TGBLA06 for borated conditions. The borated cases were considered at the beginning of life and were performed at a uniform boron concentration of 660 ppm natural boron equivalent.

For the uncontrolled cases, the agreement is within **[[ ]]**.

SVEA 96+ lattice 6026 was used to compared TGBLA06V and MCNP for the standard unbladed depletion cases. The depletion cases were compared on the basis of infinite eigenvalue where the lumped cross sections are removed and TGBLA06V isotopic concentrations are input into MCNP in order to emulate exposure. The results of these comparisons are included in Table 2.3 of Cycle 13 MCAR. The table indicates that there is no trend in the differences with exposure and that the eigenvalue differences remain within **[[ ]]** consistently through exposure.

The comparisons at the beginning of life indicate generally good agreement for cold conditions between TGBLA06 and MCNP **[[ ]]**.

The staff has concluded that the range of cases considered demonstrates that TGBLA06 is capable of determining the infinite eigenvalue within the expected differences for SVEA 96+ lattices under CLTP conditions. The staff expects closer agreement when the corrected TGBLA06AE5 code version is used and therefore the staff finds that the uncertainty determination is adequately conservative.

Fission Density Distribution Results

Figures 2.9 through 2.14 of Cycle 13 MCAR[243] illustrate the fission density distribution uncertainty as a function of void, control state, and borated condition at the beginning of exposure. Table 2.5 of Cycle 13 MCAR provides the root mean square (RMS) fission density differences for a representative SVEA 96+ lattice as a function of exposure and void. The SVEA 96+ lattice described by Table 2.5 is lattice 6026. Figures 2.9 through 2.14 show that the TGBLA06 predicted fission density distribution for lattice 6026 has the highest uncertainty, exceeding 3 percent RMS difference under cold conditions.

The comparisons to MCNP are used not only to illustrate the capabilities of the TGBLA06 method, but to also provide uncertainty input to the SVEA 96+ critical power determination.

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[243] 0000-0029-7705-MCAR, Revision 0, "Mixed Core Analysis Report (MCAR) for Hope Creek Reload 12 Cycle 13," April 2005, ADAMS Accession No. ML053190325.

For the standard depletion cases shown in Table 2.5, the fission density RMS remains below the two standard deviation range of usage criterion for GE applications **[[ ]]**.

An aggregate calculation for the uncertainty was performed and shown to be 1.63 percent for SVEA 96+ lattices when all cases are considered. This is slightly larger than the 1.44 percent for GE bundles under normal operating CLTP conditions. Considering that the depletions are performed with SVEA 96+ lattice 6026 (which shows the highest beginning of life uncertainties), the results indicate overall agreement that is consistent with GE fuel products.

The largest contributors to the uncertainty are those pins that are near the diamond shaped water channel at the center of the lattice. These results are not unexpected given that the diamond region is approximated **[[ ]]** and not modeled directly. For the fuel pins near the center of the lattice TGBLA06 consistently predicts pin powers that are lower than the MCNP predicted results **[[ ]]**.

Table 2.5 indicates that TGBLA06 predicted results more closely match MCNP results for the fission density distribution at high exposure, as seen by generally decreasing RMS differences with exposure for each void history.

PSEG provided a two dimensional pin power distribution for the dominant zone SVEA 96+ lattice as a function of exposure up to 10 GWD/ST in Figure 2.18 of Cycle 13 MCAR. The results indicate that pin peaking is most pronounced for the C lattice design at the edge of the lattice near the liquid bypass. During exposure the gadolinia loaded pins near the center water rod rapidly deplete and power increases during the early part of exposure. This is indicative of exposure in a softened neutron spectrum as a result of the enhanced slowing down source from the center water region.

The standard production depletion case comparisons show that TGBLA06 is capable of determining the fission density distribution for SVEA 96+ lattices under normal operating CLTP conditions when appropriate assumptions are used to model the water cross geometry with only a slight increase in the pin power distribution uncertainty relative to GE fuel designs.

Reactivity Feedback

GDC 11 requires the reactor core to have a negative prompt reactivity response to an increase in reactor power. The negative reactivity feedback for BWRs is a combination of the void reactivity coefficient, moderator temperature coefficient, and the Doppler coefficient. In general, at normal operating conditions, the void reactivity coefficient is orders of magnitude greater than the other inherent negative reactivity feedback coefficients.

PSEG has provided a significant amount of information regarding the lattice dynamic reactivity coefficients for SVEA 96+ and GE14 lattices in Cycle 13 MCAR.[244] These analyses were performed to demonstrate the efficacy of the TGBLA06 lattice physics code to model the reactivity feedback and depletion for SVEA 96+ and GE14 lattices. However, these analyses similarly provide the basis for demonstrating compliance with GDC 11.

[244] 0000-0029-7705-MCAR, Revision 0, “Mixed Core Analysis Report (MCAR) for Hope Creek Reload 12 Cycle 13,” April 2005, ADAMS Accession No. ML053190325

The staff therefore reviewed first the efficacy of the TGBLA06 lattice physics code to capture the void reactivity feedback phenomena at the lattice level and the ability of the PANAC11 core simulator to adequately capture the effects of fuel exposure on the nodal reactivity. The acceptable performance of the nuclear design code suite to model these phenomena provide a basis for the acceptance of downstream transient results that indicate negative reactivity feedback with increasing reactor power (and hence core average void content).

The dynamic void coefficient is calculated for each lattice in the uncontrolled state at the beginning of life (unexposed). The dynamic void coefficient is based on instantaneous void branch cases that are performed to develop the functional matrix of nuclear parameters for subsequent correlation to nodal parameters and inclusion in the PANACEA wrap up file. For all cases the instantaneous lattice reactivity is fit as a quadratic function of the relative water density for use in downstream analyses, the dynamic void coefficient for the beginning of life is different in that the quadratic expression is based on the VF as opposed to relative water density. However, based on the information provided the staff has determined that similar nuclear characteristics demonstrated by the dynamic void coefficient would effectively be translated to the full core model be means of the fitting to the functional matrix of lattice physics results. By differentiating the expression with respect to the VF, PSEG determines the sensitivity of the lattice reactivity to VF as a function of the instantaneous VF.

The comparative studies performed with TGBLA06 and MCNP indicate that the predicted SVEA 96+ void coefficients are slightly more positive than those predicted by MCNP; however, the bias and uncertainty determined for the SVEA 96+ lattices are bound by those determined for GE14 lattices. Therefore, the staff finds that the uncertainties and biases applied in NEDC-33173P conservatively bound those uncertainties observed for unexposed SVEA 96+ lattices.

At higher exposures, the buildup of plutonium (Pu) and fission products may result in a positive nodal void reactivity feedback, as show in Cycle 13 MCAR comparative results. This is particularly a concern for operating in an expanded operating domain where the higher power-to-flow ratios at EPU conditions relative to the CLTP conditions result in higher VFs in core, and therefore, harder spectrum exposure. In a harder spectrum, the buildup of Pu in the upper part of the core results in a known bias in nodal reactivity feedback for GE14 lattices that is captured in NEDC-33173P.

The nodal reactivity bias for high void exposures has not been specifically calculated for SVEA 96+ legacy fuel in the HCGS EPU Cycle 15 analysis. However, these legacy fuel bundles have been exposed for several cycles at CLTP conditions. The efficacy of the GE methods to determine nodal parameters at the CLTP conditions for SVEA 96+ fuel has been demonstrated and previously accepted by the staff. The capability of the NEDC-33173P to capture the exposure effects on nodal parameters is qualified through comparisons of measured and predicted traversing incore probe (TIP) instrument readings. Cycle follow analyses for the mixed cores at Hope Creek at CLTP conditions from cycle 9 through cycle 12 (as illustrated in figures 3.17, 3.19. and 3.21 of Cycle 13 MCAR[245]) indicate that there is no degradation of the predictive capability of the GE nuclear design methods through cycle exposure for the SVEA 96+ bundles. The differences in the Process Computer Transversing Incore Probe (PCTIP) and

[245] 0000-0029-7705-MCAR, Revision 0, “Mixed Core Analysis Report (MCAR) for Hope Creek Reload 12 Cycle 13,” April 2005, ADAMS Accession No. ML053190325

Calculated Transversing Incore Probe (CALTIP) responses are consistent with those shown for NEDC-33173P for GE fueled reactors.[246]

The predicted and measured TIP readings indicate that the GE nuclear design methods for CLTP conditions adequately model the exposure affects on nodal reactivity parameters and provides a basis for the qualification of these nodal parameters that affect the power shape, namely: the infinite eigenvalue, nodal leakage, and migration area.

The nodal parameters are predicated on a set of lattice physics parameters that are determined using TGBLA06. The TGBLA06 calculations include several depletion cases and branch cases to form the functional matrix for nuclear parameter fitting to nodal conditions. Cycle 13 MCAR includes a comparison of depletion calculations carried out at the standard void cases for SVEA 96+ lattices. Analyses were performed in parallel whereby the “no-lumped” TGBLA lattices were directly compared to MCNP predictions of the infinite eigenvalue at a series of exposure points for SVEA 96+ lattice 6026. “No-lumped” lattices refer to TGBLA calculated material compositions as a function of exposure where fission products and gadolinia tails that are not explicitly tracked during the depletion are artificially removed in order to provide a consistent basis for comparison to MCNP. The results in Table 2.3 of MCAR C13 (0000-0029-7705-MCAR) indicate that at the standard void depletion cases that the TGBLA06V code is capable of predicting the SVEA 96+ infinite eigenvalue within **[[ ]]**. Therefore, the analyses demonstrate that the efficacy of TGBLA06 to determine infinite eigenvalue does not degrade with exposure.

A dynamic void coefficient is also calculated based on the lattice results, but since the reactivity differences are based on lattices that have been exposed at different VFs, the quoted dynamic void coefficient in Table 2.3 of MCAR C13 (0000-0029-7705-MCAR) carries no physical meaning.

Therefore, the staff specifically reviewed any potential nodal reactivity biases in the GE methods for SVEA 96+ that may impact cycle specific safety analyses arising from exposure of the legacy fuel at higher VFs than CLTP conditions. The RLP as described in the HCGS EPU MCAR (0000-0031-9422-MCAR)[247] provides exposure dependent power to flow ratios for the SVEA 96+ legacy fuel. The average thrice burnt legacy fuel is predominantly loaded in the core periphery, where the bundle power is lower. A combination of high exposure (and subsequently low bundle averaged reactivity) and the RLP result in low bundle powers for the SVEA 96+ bundles during cycle exposure relative to the GE14 bundles, in particular the once burnt GE14 bundles.

The analyses in 0000-0031-9422-MCAR demonstrate that the RLP results in lower bundle powers for the SVEA 96+ legacy fuel, but also demonstrates that the ratio of the bundle power to bundle flow for these bundles in particular is similar to that for the CLTP operating conditions. Therefore, during exposure over Cycle 15 the SVEA 96+ fuel will not experience higher VFs than those included in the qualification shown in MCAR C13 (0000-0029-7705-MCAR). The staff therefore agrees that the ability of the GE methods to model the depletion, and subsequently the nodal reactivity feedback for the SVEA 96+ bundles as loaded in the HCGS EPU MCAR RLP, will be consistent with the demonstrated performance for CLTP conditions.

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[246] GE letter (MFN-05-141) to NRC dated November 28, 2005, Subject: GE Licensing Topical Report NEDC-33006P, Revision 2, "Maximum Extended Load Line Limit Analysis Plus," (TAC No. MB6157) ADAMS Accession No. ML053300526
[247] 0000-0031-9433-MCAR, Revision 0, “Mixed Core Analysis Report (MCAR) for Hope Creek Extended Power Uprate,” April 2005, ADAMS Accession No. ML053190286

The core reactivity feedback to increasing power is based on the concert of nodal effects. PSEG has demonstrated in Cycle 13 MCAR[248] that the legacy fuel has an inherent negative feedback at the beginning of life, and that the fuel will be exposed in Cycle 15 under conditions substantial similar to those in Cycle 13, therefore the staff has concluded that the analyses performed with the GE methods will predict the local void reactivity effects for the SVEA 96+ fuel bundles sufficiently accurately.

Demonstration transient analyses for the TT without bypass included in the appendix to 0000-0031-9433-MCAR, (Figure 3) demonstrate core wide negative void reactivity feedback for a mixed core containing SVEA 96+ fuel bundles. This analysis confirms that SVEA 96+ fuel bundles for the predominance of exposure have a negative nodal reactivity feedback with increasing VF.

The staff further reviewed the RLP in Cycle 13 MCAR to determine if the fuel is loaded in such a way to preclude the possibility of local reactivity effects in the highly exposed legacy bundles that may result in positive feedback with increasing power.

The RLP, as depicted in Figure 5.1 of 0000-0031-9433-IMLTR-SUP1,[249] has two features that preclude local positive feedback effects:

- The predominance of the legacy fuel is loaded at the core periphery. The peripheral bundles are in low flux regions of the core, and hence a low adjoint region of the core. Therefore, changes in core reactivity are minimally influenced by the peripheral bundles, and the power produced in these bundles is driven by leakage neutrons in the higher reactivity bundles towards the core center.
- The remaining bundles are distributed through out the core in a color-set pattern. Here color-set refers to the loading of fresh, once, twice, and thrice burnt fuel in a four bundle repeating array in the core. The color-set loading pattern ensures that local reactivity effects are driven by a combination of the four bundle response, since the neutron mean free path at operating conditions ensures strong coupling between the bundles in the color-set. Previous analyses have demonstrated that the other bundles will have strong negative reactivity feedback coefficients for the range of exposures expected in Cycle 15.

Therefore, based on the information supplied by PSEG the NRC staff has reasonable assurance that operating at EPU conditions with SVEA 96+ legacy fuel does not impact the ability of the GE methods as described in NEDC-33173P to determine nodal reactivity effects for the legacy fuel for HCGS Cycle 15 given the EPU MCAR.

The NRC staff has also determined, based on a combination of lattice, core follow, and transient analyses and the RLP that there is reasonable assurance that the HCGS Cycle 15 core design will meet the requirements of GDC 11.

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[248] 0000-0029-7705-MCAR, Revision 0, “Mixed Core Analysis Report (MCAR) for Hope Creek Reload 12 Cycle 13,” April 2005, ADAMS Accession No. ML053190325

[249] 0000-0031-9433-IMLTR-SUP1, Revision 0, “Interim Methods LTR Supplement for Hope Creek Extended Power Update,” July 2006, ADAMS Accession No. ML062680455

Thermal Margin Assessment

The MLHGR is the maximum local LHGR, more specifically the fuel rod with the highest surface heat flux at any nodal plane in a fuel bundle in the core. The MLHGR operating limit is bundle-type dependent and included in a plant's cycle operating limits report. The LHGR is monitored to assure that all mechanical design requirements are met. The fuel will not be permitted to be operated at LHGR values greater than those found to be acceptable within the body of the safety analysis under normal operating conditions. Under abnormal conditions, including the maximum overpower condition, the MLHGR will not cause fuel melting or cause the strain limit to be exceeded.

The MCPR is the minimum critical power ratio of all of the fuel bundles. The CPR for any bundle is the ratio of the bundle power that would result in transition boiling to the current bundle power. Therefore, the bundle with the smallest CPR has the smallest margin to transition boiling. The CPR is a function of several parameters; the most important are bundle power, bundle flow, the local power distribution and the details of the bundle mechanical design.

The plant Operating Limit MCPR (OLMCPR) is established by considering the limiting AOOs for each operating cycle. The OLMCPR is determined such that 99.9 percent of the rods avoid boiling transition during the limiting analyzed AOO.

To meet the requirements of GDC 10 the HCGS Cycle 15 RLP analyses must demonstrate that:

- Under abnormal conditions (including maximum overpower), the MLHGR will not cause the fuel to exceed mechanical design limits.
- The MCPR during normal operation will remain greater than the OLMCPR to avoid boiling transition during normal operation and AOOs.

Thermal Mechanical Margin Assessment

Operating below the MLHGR limit ensures that GDC 10 is met by assuring adequate protection against thermal mechanical cladding failure. The limit is an exposure dependent limit that is calculated and included in the cycle operating limits report. For the specific HCGS Cycle 15 RLP, the most limiting bundles in terms of the MLHGR limit are expected to be the thrice burnt SVEA 96+ legacy fuel bundles. As shown in the Cycle 13 MCAR,[250] pin power uncertainties for the SVEA 96+ bundles are on the order of 1percent to 2 percent. The MLHGR limit calculation inherently assumed a **[[ ]]** uncertainty in pin power, which bounds the demonstrated uncertainty range. However, uncertainties in the nodal flux gradient have not been demonstrated, and there are observable biases for fuel pins at the center of the lattice near the water diamond on the order of **[[ ]]**.

The PANACEA nodal flux gradient model is based on the lattice averaged migration area and is used to predict pin power distributions based on the two dimensional peaking factors and the gross flux gradient across the node. This feature is included in the PANAC11 version of the code, and represents a significant improvement in pin power modeling capabilities relative to earlier versions of PANACEA. Migration area comparisons between MCNP and TGBLA06 for SVEA 96+ lattices have not been provided, but based on the HCGS EPU MCAR, and explicit

[250] 0000-0029-7705-MCAR, Revision 0, "Mixed Core Analysis Report (MCAR) for Hope Creek Reload 12 Cycle 13," April 2005, ADAMS Accession No. ML053190325

calculations performed for representative GE lattices during the review of NEDC-33173P, there is reasonable assurance that even large uncertainties in the migration area (of approximately 10 percent) do not significantly perturb pin power distribution results. Furthermore, the SVEA 96+ water cross wings tend to flatten the lattice power distribution by design and analyses in the Cycle 13 MCAR indicate that the methods are capable of predicting TIP measurements of the axial power shape, indicating that there are no gross errors in the nodal parameters.

Therefore, while the pin power uncertainty has not been specifically quantified, the specific approach to flatten radial power for the HCGS Cycle 15 core, and experience based on GE lattices would indicate that any additional uncertainty in pin power attributable to the unique design features of the SVEA 96+ will most likely be negligible when compared to uncertainties in the infinite two dimensional power distribution.

For HCGS EPU Cycle 15, the SVEA 96+ legacy bundles have accrued several cycles of exposure under CLTP conditions; there are eight SVEA 96+ that have accrued only two cycles of exposure. Therefore, the staff considered the under prediction of the power in the center region of the lattice by **[[ ]]**. For several reasons as discussed below, the NRC staff finds that the HCGS EPU MCAR RLP and analyses demonstrate adequate margin to the MLHGR limit for the SVEA 96+ legacy bundles:

- The central pins have been exposed under a soft neutron spectrum for several cycles, and therefore the highly absorbing Gd and fissile loading in these pins are greatly depleted and the power distribution is expected to peak at the edge of the lattice, where TGBLA06 more accurately models the pin power distribution.
- The MLHGR limit is conservatively determined by assuming that the fuel operates along the limit envelope with exposure, while HCGS Cycle 15 follow analyses demonstrate that the fuel operates substantially beneath this limit prior to the most limiting exposure (Figure 5.4 of 0000-0031-9433-MCAR[251])
- There is substantial margin to the SL for the RLP, despite exceeding the design target near the MOC, and the margin to the SL at the most limiting point in cycle exposure is greater than 10 percent.

Therefore, the NRC staff finds that adequate and acceptable margin has been demonstrated for the SVEA 96+ legacy bundles given the accuracy of the GE methods as provided in NEDC-33173P, the operating history of the legacy fuel, and the predicted operating conditions for the legacy fuel in HCGS EPU MCAR.

Critical Power Margin Assessment

Operating above the OLMCPR meets the requirements of GDC 10 by ensuring that 99.9 percent of fuel rods avoid transition boiling during normal operation and AOOs. The OLMCPR is predicated on the safety limit MCPR (SLMCPR) and the ΔCPR/initial critical power ratio (ICPR) for the limiting AOO. Compliance with the OLMCPR during normal operation is tracked by the maximum fraction of limiting CPR (MFLCPR), which is the ratio of the OLMCPR to the core MCPR.

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[251] 0000-0031-9433-MCAR, Revision 0, “Mixed Core Analysis Report (MCAR) for Hope Creek Extended Power Uprate,” April 2005, ADAMS Accession No. ML053190286

PSEG calculates the CPR on a bundle-by-bundle basis given the current bundle conditions predicted by the steady state methods and an applicable critical power correlation and an iteration technique on channel power. The GEXL-80 correlation is used to determine the CPR for the SVEA 96+ legacy fuel. The GEXL80 correlation has been approved for this purpose when exercised within the conditions and limitations are documented in the staff's SER.[252]

The NRC staff SER for the application of the GEXL80 correlation concluded that the correlation is reasonable based on the hypothetical database used in its generation as uncertainties in the approach have been conservatively treated and appropriately included in the correlation. The NRC staff notes that the applicability of the correlation is limited to the range of data in the hypothetical database and further limited by the SVEA 96+ raw data set included in the original assessment. Therefore, the staff has found that the GEXL80 correlation is only applicable to at least once burnt SVEA 96+ fuel when it is loaded in non-limiting locations in the core, and only applicable to Hope Creek mixed cores.

Given the placement of the SVEA 96+ legacy fuel in the Hope Creek Cycle 15 RLP and the depletion of these fuel assemblies, the limiting bundles in terms of critical power performance for HCGS Cycle 15 will be the GE14 high powered bundles; therefore, the staff finds that the use of the GEXL80 critical power correlation is appropriate and acceptable. The staff has reviewed the efficacy of the GE methods to capture reactivity feedback effects and has determined that the methods are acceptable for modeling the effects of void reactivity feedback for the SVEA 96+ fuel bundles as they are operated in Cycle 15. Therefore, the NRC staff finds that the predicted CPR for SVEA 96+ fuel bundles is acceptable and that the inclusion of SVEA 96+ fuel bundles will not adversely impact the capability of the GE Interim Methods to predict the limiting ΔCPR/ICPR.

PSEG provided a plot of the MFLCPR through cycle exposure predicted based on the HCGS EPU Cycle 15 RLP in Figure 5.4 of 0000-0031-9433-MCAR.[253] The MFLCPR remains well below unity (maximum value is less than 0.90) and also within the design target.

Furthermore, there is sufficient conservatism in the analysis of the SVEA 96+ bundles such that operating within the prescribed limits set forth by the NEDC-33173P to ensure compliance with GDC 10. The OLMCPR for EPU conditions include conservative adders in the NEDC-33173P to account for nuclear methods uncertainties for expanded operating domains. These adders are included in both the SLMCPR and OLMCPR to account for these uncertainties, however, the SVEA 96+ fuel bundles experience a range of bundle powers and flows that are substantially similar to the CLTP conditions, and therefore, these additional adders are conservative for the SVEA 96+ fuel bundles.

Therefore, the NRC staff finds that the inclusion of SVEA 96+ legacy fuel, as analyzed based on NEDC-33173P and the GEXL80 critical power correlation, adequately demonstrate that the HCGS EPU Cycle 15 RLP meets the partial requirements of GDC 10 to avoid boiling transition.

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[252] PSEG letter (LR-N07-0102) to NRC dated May 10, 2007, "Response to Request for Additional Information Request for License Amendment - Extended Power Uprate" ADAMS Accession No. ML071360375

[253] 0000-0031-9433-MCAR, Revision 0, "Mixed Core Analysis Report (MCAR) for Hope Creek Extended Power Uprate," April 2005, ADAMS Accession No. ML053190286

Shutdown Margin

GDC 26 requires that a reactivity control system be included that is capable of holding the reactor subcritical under cold conditions assuming a single failure and GDC 27 requires that a separate and redundant capability be included in the plant that is based on a fully diverse design principle. These requirements are met through the control rod system and the SLCS.

Compliance with these GDC are demonstrated by calculating the cold critical eigenvalue using TGBLA06/PANAC11 nuclear methods and known biases. Calculational efficacy of the nuclear design codes has already been demonstrated and approved for cold reactivity calculations and would apply to both CLTP and EPU HCGS core designs, however, the cold critical eigenvalue bias is based on a combination of operational experience and engineering judgment.

As cold conditions typical of shutdown are the same for the CLTP and EPU core designs, comparative studies performed for the Cycle 13 MCAR are applicable to the Cycle 15 basis for SDM. These comparisons described in NEDC-32523P-A[254] indicate that the GE methods are capable of predicting nodal parameters for borated conditions for SVEA 96+ fuel accurately and any uncertainties in regards to bladed SVEA 96+ calculations for nodal reactivity has been previously quantified.

The design acceptance criterion for SDM is 1 percent Δk to conservatively account for these uncertainties. However, another component of the SDM is the bias. The cold critical eigenvalue bias is typically sensitive to the batch reload fraction and fuel design.[255] The HPGS Cycle 15 EPU RLP core cold critical eigenvalue bias is based on trends observed for several high power density BWRs and the previous two cycles for Hope Creek. The cold critical eigenvalue trend is consistent with the fleet average. The batch reload fraction for HCGS cycle 15 is not exceptionally large compared with those reactors in the set of high power density reference BWRs, and the bias is less than **[[ ]]**. Previous experience in the high power density reference BWRs and previous cycles at HCGS indicate differences between predicted and actual eigenvalues at cold conditions on the order of **[[ ]]**.

Applicability of these methods to determine eigenvalue trends for SVEA 96+ fuel has been demonstrated for the previous two cycles at Hope Creek where differences between the predicted and actual eigenvalues at the BOC were within 0.09 percent Δk

Upon review of the information included in 0000-0031-9433-MCAR and 0000-0031-9433-IMLTR-SUP1[256], the NRC staff finds that:

- The approved PANAC11 methodology remains applicable to both the currently licensed thermal power reactor design cold conditions as well as the cold conditions for the RLP for HCGS EPU Cycle 15.

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[254] Section 4.8 of Supplement 1 of GE Licensing Topical Report, NEDC-32523P-A (February 2000), "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate" (ELTR2) ADAMS Accession No. ML003712826

[255] GE letter (MFN-05-141) to NRC dated November 28, 2005, Subject: GE Licensing Topical Report NEDC-33006P, Revision 2, "Maximum Extended Load Line Limit Analysis Plus," (TAC No. MB6157) ADAMS Accession No. ML053300526

[256] 0000-0031-9433-MCAR, Revision 0, "Mixed Core Analysis Report (MCAR) for Hope Creek Extended Power Uprate," April 2005 (ADAMS Accession No. ML053190286) and 0000-0031-9433-IMLTR-SUP1, Revision 0, "Interim Methods LTR Supplement for Hope Creek Extended Power Update," July 2006 (ADAMS Accession No. ML062680455)

- The batch reload fraction is not beyond the experience database and therefore not expected to have a large contribution to the cold critical eigenvalue trend
- The HCGS cold critical design basis eigenvalue is higher than the fleet averaged bias, indicating a slight level of conservatism in the SDM assessment
- TGBLA06/PANAC11 have been qualified to perform cold and borated analyses with SVEA 96+ fuel lattices
- The 1-percent delta-k design acceptance criterion is adequate to capture known uncertainties conservatively
- SDM analyses demonstrate that there is significant margin to the acceptance criterion (greater than 1.25-percent delta-k for the control rod system assuming the strongest rod stuck out at the EOC limiting point, and 3.25-percent delta-k for the SLCS at the limiting point) according to NEDC-32424P-A.[257]

Therefore, the analyses adequately demonstrate compliance with the requirements of GDC 26 and GDC 27 for the HCGS EPU Cycle 15 RLP core design.

Stability

GDC 12 requires that oscillations be readily detected and suppressed. The scope of the NRC staff's review for the mixed core analysis is limited to those areas where neutronic modeling of the SVEA 96+ fuel bundles may impact numerical results of stability analyses, namely in the determination of the DIVOM (ΔCPR/ICPR versus Oscillation Magnitude) curve. The DIVOM curve is typically linear and the slope is an indication of the channel thermal hydraulic response to an oscillation. A larger slope is indicative of a more adverse response.
PSEG provided reference analyses for the determination of the DIVOM curve slope for the Cycle 14 HCGS core in NEDC-33186P, "MELLLA TRACG DIVOM Evaluation for Hope Creek at CPPU Conditions," and NEDO-33188, "MELLLA Option III Stability Evaluation for Hope Creek at CPPU Conditions."[258] The purpose of these analyses is to demonstrate the calculational capabilities of the GE methods for mixed core analyses. While application of NEDC-33173P for GE fuel bundles up to GE14 has been demonstrated, the NRC staff reviewed the application of these methods to the HCGS Cycle 14 analyses in order to determine the acceptability of the NEDC-33173P to adequately model the impact of the legacy fuel on regional oscillations.

Steady state analyses and the RLP provided in 0000-0031-9433-MCAR indicate that the SVEA 96+ legacy fuel will be loaded predominantly near the core periphery and will be operated at bundle power to flow ratios that are substantially lower than those for the fresher GE fuel bundles. Overall, the combination of these analyses and the RLP indicate two features of the SVEA 96+ fuel, as operated, that influence the results of any stability analyses:

- The lower power-to-flow ratios for these bundles indicates that the legacy fuel channels are less susceptible to undamped thermal hydraulic (density wave) instabilities because the single-phase to two-phase pressure drop will be much greater for these lower powered bundles.
- The depletion of these bundles and the loading pattern ensure that the reactivity worth of these bundles are low, therefore, they are unlikely to drive neighboring bundles through neutronic coupling and changes in the thermal hydraulic conditions of low adjoint bundles

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[257] Appendix K of General Electric Licensing Topical Report (LTR) NEDC-32424P-A (February 1999), "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," (ELTR1) ADAMS Accession No. ML003680231
[258] ADAMS Accession Nos. ML053180383 and ML053180372, respectively

contributing minimally to feeding potential undamped core wide or regional oscillatory modes.

The Cycle 14 demonstration analysis at EPU conditions provided in NEDC-33186P[259] shows results of transient analyses used to determine the slope of the DIVOM curve. The analysis was performed using TRACG04.

PANAC11 is used in the analysis to calculate the first harmonic flux shape in order to perform downstream regional mode oscillation calculations with TRACG. The first harmonic power shape and the fundamental power shape are combined in order to group thermal hydraulic channels in TRACG. Flow perturbations are used to observe the transient response for the limiting channels that are symmetric about the first harmonic symmetry plane. In the demonstration analyses, the limiting channels are the high power-to-flow ratio GE14 bundles located at the first harmonic peaks.

As a cycle specific DIVOM, curve must be determined due to unique aspects of core loading patterns and reactor dynamic behavior the staff requested additional information in regards to the SVEA 96+ fuel bundles that are specifically in the color-set arrays in the RLP. Namely, the staff requested that PSEG perform a demonstration analysis comparing the DIVOM curve slope predicated on the limiting SVEA 96+ fuel bundle and compare the result to that determined for the limiting GE14 bundle.

In cases where the SVEA 96+ limiting bundle predicted DIVOM slope is significantly lower than the GE14 fuel bundle predicated slope, there is reasonable assurance that even with greater uncertainties in the dynamic response at EPU conditions that oscillations in the legacy fuel are sufficiently damped that these bundles in the non-peripheral regions of the core do not appreciably influence the thermal hydraulic instability phenomena in the more limiting bundles. In response to the NRC staff's RAI,[260] PSEG provided the results of a TRACG04 demonstration analysis for SVEA 96+ legacy fuel that indicates a DIVOM slope less than 0.3, which is to be compared to the GE14 predicated DIVOM slope of approximately 0.8. Based on the comparison of these slopes, the NRC staff has determined that the peripheral SVEA 96+ legacy fuel and the color-set loaded SVEA 96+ fuel lack sufficient reactivity or unstable configurations to influence limiting core stability analyses; therefore, quantification of any heretofore unaccounted for uncertainties in the dynamic response for the SVEA 96+ legacy fuel bundles would not appreciably affect the outcome of the stability analyses for the HCGS Cycle 15 assessment.

Additionally, NEDC-33173P includes OPRM set point determination conditions for long term stability solution Option III plants that account for the influence of bypass voiding. The conservative set-point set down imposed by the NRC staff SE for NEDC-33173P would ensure a conservative set-point for the SVEA 96+ bundles where the bundle power, and subsequent direct moderator heating source to the bypass around these bundles, would preclude appreciable void formation.

Therefore, based on the HCGS EPU Cycle 15 RLP, whereby SVEA 96+ legacy fuel bundles are loaded predominantly in low adjoint regions of the core, and the demonstration analyses which

[259] NEDC-33186P, "MELLLA TRACG DIVOM Evaluation for Hope Creek at CPPU Conditions," General Electric, April 2005, ADAMS Accession No. ML053180383
[260] ADAMS Accession No. ML071500294

indicate negligible contributions from the stable SVEA 96+ fuel bundles for limiting regional oscillatory behavior, the NRC staff has found that the NEDC-33173P is adequate to support the determination of the DIVOM slope and OPRM set points for HCGS EPU Cycle 15 when exercised within the conditions and limitations stated in the staff's SER[261] and the inclusion of the legacy fuel will not have a safety significant impact on the results of these analyses.

Conclusion

The NRC staff has evaluated the HCGS EPU application to assess the acceptability of the GE neutronic and thermal-hydraulic analytical methods and code systems used to demonstrate compliance with prescribed GDC at EPU conditions. The NRC staff evaluation supports the conclusion that there is reasonable assurance that application of NEDC-33173P to HCGS EPU Cycle 15 will not adversely impact the plant ability to demonstrate compliance with the regulatory requirements. The NRC staff finds that inclusion of the SVEA 96+ legacy fuel for HCGS Cycle 15 will be acceptable.

The staff finds that the NEDC-33173P approach is acceptable for HCGS EPU Cycle 15 for the following reasons:

(1) PSEG has addressed the limitations associated with the NRC staff SE for NEDC-33173P and has committed to the following actions:

  a. HCGS will incorporate the additional 0.02 margin to the cycle specific SLMCPR for EPU cycles.
  b. HCGS will use R-factor calculations consistent with the predicted axial void conditions for EPU cycles.
  c. HCGS will provide the limiting GE14 LOCA analysis at EPU conditions using top-peaked axial power shape.
  d. HCGS will confirm that the bypass voiding for HCGS's initial EPU cycle will to be below 5 percent.
  e. HCGS EPU reload analysis will account for the calibration errors due to bypass voiding when determining the stability detect and suppress setpoints.
  f. HCGS will incorporate the additional 0.01 margin to OLMCPR for EPU cycles.

(2) The NRC staff has concluded that the range of lattice eigenvalue cases considered demonstrates that TGBLA06 is capable of determining the infinite eigenvalue within the expected differences for SVEA 96+ lattices under CLTP conditions. The NRC staff finds that the uncertainty determination is adequately conservative.

(3) The standard production depletion case comparisons show that TGBLA06 is capable of determining the fission density distribution for SVEA 96+ lattices under normal operating CLTP conditions when appropriate assumptions are used to model the water cross geometry with only a slight increase in the pin power distribution uncertainty relative to GE fuel designs.

[261] Final Safety Evaluation for Global Nuclear Fuel (GNF) Licensing Topical Report NEDC-33107P, "GEXL80 Correlation for SVEA96+ FUEL" (TAC NO. MC0666), dated July 19, 2004, ADAMS Accession No. ML041980329)

(4) The predominance of the legacy fuel is loaded at the core periphery. The peripheral bundles are in low flux regions of the core, and hence a low adjoint region of the core. Therefore, changes in core reactivity are minimally influenced by the peripheral bundles, and the power produced in these bundles is driven by leakage neutrons in the higher reactivity bundles towards the core center.

(5) The remaining bundles are distributed throughout the core in a color-set pattern. Here color-set refers to the loading of fresh, once, twice, and thrice burnt fuel in a four bundle repeating array in the core. The color-set loading pattern ensures that local reactivity effects are driven by a combination of the four bundle response, since the neutron mean free path at operating conditions ensures strong coupling between the bundles in the color-set. Previous analyses have demonstrated that the other bundles will have strong negative reactivity feedback coefficients for the range of exposures expected in Cycle 15.

(6) The central pins have been exposed under a soft neutron spectrum for several cycles, and therefore the highly absorbing Gd and fissile loading in these pins are greatly depleted and the power distribution is expected to peak at the edge of the lattice, where TGBLA06 more accurately models the pin power distribution.

(7) The MLHGR limit is conservatively determined by assuming that the fuel operates along the limit envelope with exposure, while HCGS EPU MCAR follow analyses demonstrate that the fuel operates substantially beneath this limit prior to the most limiting exposure (Figure 5.4 of 0000-0031-9433-MCAR).[262]

(8) There is substantial margin to the SL for the RLP, and the margin to the SL, at the most limiting point in cycle exposure, is greater than 10 percent.

(9) Given the placement of the SVEA 96+ legacy fuel in the HCGS Cycle15 RLP and the depletion of these fuel assemblies, the staff finds that the use of the GEXL80 critical power correlation is appropriate and acceptable.

(10) The OLMCPR for EPU conditions include conservative adders in the GE Interim Method to account for nuclear methods uncertainties for expanded operating domains. These adders are included in both the SLMCPR and OLMCPR to account for these uncertainties, however, the SVEA 96+ fuel bundles experience a range of bundle powers and flows that are substantially similar to the CLTP conditions, and therefore, these additional adders are conservative for the SVEA 96+ fuel bundles.

(11) The approved PANAC11 methodology remains applicable to both the currently licensed thermal power reactor design cold conditions as well as the cold conditions for the RLP for HCGS EPU Cycle 15.

(12) The batch reload fraction is not beyond the experience database and therefore not expected to have a large contribution to the cold critical eigenvalue trend.

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[262] 0000-0031-9433-MCAR, Revision 0, “Mixed Core Analysis Report (MCAR) for Hope Creek Extended Power Uprate,” April 2005, ADAMS Accession No. ML053190286

(13) The HCGS cold critical design basis eigenvalue is higher than the fleet averaged bias, indicating a slight level of conservatism in the SDM assessment.

(14) TGBLA06/PANAC11 has been qualified to perform cold and borated analyses with SVEA 96+ fuel lattices.

(15) The 1-percent delta-k design acceptance criterion is adequate to capture known uncertainties conservatively.

(16) SDM analyses demonstrate that there is significant margin to the acceptance criterion (greater than 1.25-percent delta-k for the control rod system assuming the strongest rod stuck out at the EOC limiting point, and 3.25-percent delta-k for the SLCS at the limiting point) according to 0000-0031-9433-MCAR.

(17) The lower power to flow ratios for these bundles indicates that the legacy fuel channels are less susceptible to undamped thermal hydraulic (density wave) instabilities because the single phase to two phase pressure drop will be much greater for SVEA 96+ bundles than for the GE14 fuel bundles.

(18) The depletion of these bundles and the loading pattern ensure that the reactivity worth of SVEA 96+ bundles are low, therefore, they are unlikely to drive neighboring bundles through neutronic coupling and changes in the thermal hydraulic conditions of low adjoint bundles contribute minimally to feeding potential undamped core wide or regional oscillatory modes.

(19) NEDC-33173P includes an OPRM set point determination conditions that account for the influence of bypass voiding. The conservative set point set down imposed by the NRC staff SE for NEDC-33173P would ensure a conservative set point for the SVEA 96+ bundles where the bundle power, and subsequent direct moderator heating source to the bypass around these bundles, would preclude appreciable void formation.

2.9 Source Terms and Radiological Consequences Analyses

2.9.1 Source Terms for Radwaste Systems Analyses

Regulatory Evaluation

The NRC staff reviewed the radioactive source term associated with EPUs to ensure the adequacy of the sources of radioactivity used by the licensee as input to calculations to verify that the radioactive waste management systems have adequate capacity for the treatment of radioactive liquid and gaseous wastes. Approved GE LTR NEDC-32424P-A, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," (ELTR1) Section 5.4 requires that the radiological consequences be evaluated to show that the NRC regulations are met for uprated power conditions. 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 plant's UFSAR related to LWMS and GWMS. 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; and (2) 10 CFR Part 50, Appendix I, insofar as it establishes numerical guides for design objectives and limiting conditions for operation to meet the "ALARA" criterion. Specific review criteria are contained in SRP Section 11.1.

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, leakage from the fuel, radioactive decay and removal by coolant purification systems. The analyses supporting the EPU amendments included a core isotopic source term calculated for the EPU conditions, and were performed with consideration of, and are applicable to, both non-GE (legacy) fuel and GE14 fuel. The assumed inventory of fission products in the reactor core and available for release to the containment is based on the maximum power level of 4031 MWt corresponding to current fuel enrichment and fuel burnup, which is 1.22 times the HCGS original licensed thermal power (OLTP) of 3293 MWt, including 2 percent instrumentation uncertainty.

PSEG discussed the impact of the EPU on the radiation sources in the reactor coolant in Section 8.4 of NEDC-33076P, "Safety Analysis Report for Hope Creek Constant Pressure Power Uprate," Revision 2 (referred to as the PUSAR) which was included in Attachment 4 of the September 18, 2006, EPU submittal letter. Radiation sources in the reactor coolant include activation products, activated corrosion products, and fission products. PSEG used the guidelines in GE approved topical report NEDC-33004P-A, Revision 4 (CLTR), Section 8.4 to inform its evaluation of the reactor coolant and source terms. The licensee's reactor coolant radiation sources evaluations considered GE-14 fuel and earlier design fuel at HCGS.

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 non-radioactive isotope oxygen-16 (O-16) is activated to become radioactive nitrogen^{16} (N^{16}) by a neutron-proton reaction as it passes through the neutron-rich core at power. Coolant activation, especially N^{16} activity, is the dominant source of radiation in the turbine building and in the lower regions of the drywell. The increase in activation of the water in the core region **[[** **]]**. PSEG's evaluation shows that the current operation with HWC demonstrates sufficient margin in design to allow operations with enhanced activation products. The increase in N-16 in the turbine components due to the proposed CPPU is approximately 16 percent for a 20 percent increase in steam flow. This can be compared to the factor of 4.3 increase in N-16 due to HWC. The staff finds that the licensee's evaluation follows the guidelines in CLTR and SRP 11.1 and is, therefore, acceptable. The staff considered GE proprietary information to make its determination.

Activated corrosion products are the result of metallic corrosion products contained in the coolant water being activated by nuclear reactions as they pass through the core region. Under EPU conditions, both the FW flow and the activation rate in reactor region increase with power. This results in an increase in activated corrosion product production. PSEG calculated that the corrosion product concentrations do not exceed the design basis concentrations as a consequence of the CPPU. Therefore, no change is required in the HGCS design basis activated corrosion product concentrations for the CPPU.

Fission products in the reactor coolant are present in the steam and in the reactor water as a result of minimal normal operating releases from the fuel rods. The activity in the steam is also the noble gas offgas that is included in the HCGS design. An evaluation of steam fission and corrosion products based upon American National Standards Institute (ANSI) 18.1 methodology at CPPU conditions with the proposed revised moisture content limits, show the plant design basis to be bounding with respect to CPPU predicted concentrations. Using the current HCGS licensing basis methodology, PSEG calculated offgas rates for the EPU after 30 minutes decay that are well below the original design basis of 0.1 curies/second (Ci/sec). Therefore, the staff agrees with the licensee that the current HCGS design basis for offgas activity remains bounding for the EPU.

The fission product activity in the reactor water, like the activity in the steam, is the result of minute releases from the fuel rods. The evaluation of activity levels for fission products at CPPU conditions using the HCGS current licensing basis methodology remains bounded by the design basis. The TS limit for reactor water fission product concentration does not change for the CPPU. The staff finds this acceptable.

Based on the above evaluations, and considering that the licensee has used methodologies in the current HCGS licensing basis to evaluate the impact of the EPU on the radiation sources in the reactor coolant, the staff finds the licensee's evaluation acceptable.

Conclusion

The NRC staff has reviewed the radioactive source term in the reactor coolant and steam 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, 10 CFR Part 50, Appendix I, and GDC-60. Therefore, the NRC staff finds the proposed EPU acceptable with respect to source terms for radwaste systems analysis.

2.9.2 Radiological Consequences Analyses Using Alternative Source Terms

Regulatory Evaluation

The NRC staff reviewed the DBA radiological consequences analyses submitted by the licensee in support of the EPU. The radiological consequences analyses reviewed are the LOCA, FHA, CRDA, main steam line break, instrument line pipe break accident (ILPBA). The NRC staff's review for each accident analysis included: (1) the sequence of events; and (2) models, assumptions, and values of parameter inputs used by the licensee for the calculation of the total effective dose equivalent (TEDE). The NRC's acceptance criteria for radiological consequences analyses using an AST are based on: (1) 10 CFR 50.67, insofar as it sets standards for radiological consequences of a postulated accident; and (2) GDC-19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem TEDE, as defined in 10 CFR 50.2, for the duration of the accident. Specific review criteria are contained in SRP Section 15.0.1.

Technical Evaluation

On October 3, 2001, the staff issued Amendment 134 that used AST.[263]

The impact of the EPU on the radiological consequences of DBAs is discussed in Section 9.2, of the PUSAR. In support of the EPU amendment request, PSEG evaluated all significant DBAs currently analyzed for radiological consequences in the HCGS UFSAR. These events are the LOCA, MSLB, CRDA, FHA, and ILPBA. The staff's evaluation of each of the reanalyzed DBA radiological consequences analyses are discussed in detail below.

In its dose calculations, the licensee used the RADionuclide Transport and Removal And Dose Estimation (RADTRAD) computer code, Version 3.02. The RADTRAD code was developed by Sandia National Laboratories, the NRC's technical contractor, for the staff to use in establishing fission product transport and removal models and in estimating radiological doses at selected receptors at nuclear power plants. The licensee submitted the inputs to, and outputs from, the code, along with the resulting radiological consequences at the exclusion area boundary (EAB), in the low population zone (LPZ), and the control room. Atmospheric dispersion factors (X/Qs) were previously approved in Amendment No. 146 and are listed in Table 2.9.7.

2.9.2.1 Radiological Consequences of Control Rod Drop Accident

This accident analysis postulates a sequence of mechanical failures that result in the rapid removal (i.e., drop) of a control rod. A reactor trip will occur. Localized damage to fuel cladding and a limited amount of fuel melt are projected. The MSIVs are assumed to remain open for the duration of the event. For the dose consequence analysis, it was assumed that 850 of the fuel rods in the core were damaged, with melting occurring in 0.77 percent of the damaged rods. A core average radial peaking factor of 1.75 was used in the analysis. These assumptions are the same as their current licensing basis and are not impacted by the EPU. For releases from the breached fuel, 10 percent of the core inventory of noble gases and iodines are assumed to be in the fuel gap. For releases attributed to fuel melting, 100 percent of the noble gases and 50 percent of the iodines are assumed to be released to the reactor coolant. The analysis

[263] ADAMS Accession No. ML012600176

assumes that the fission products released from the damaged fuel are instantaneously transported to the main condenser. It is assumed that 100 percent of the noble gases, 10 percent of the iodine, and 1 percent of the remaining radionuclides are assumed to reach the turbine and condensers. Of the activity that reaches the turbine and condenser, 100 percent of the noble gases, 10 percent of the iodine, and 1 percent of the particulate radionuclides are available for release to the environment. The release from the turbine and condenser is modeled as 1.0 percent per day for 24 hours as a ground level release. These assumptions are in accordance with RG 1.183 and are, therefore, acceptable.

The licensee considered the possible release pathways and determined that the post-CRDA release through the isolated condenser is bounding for release through the mechanical vacuum pump (MVP) during startup or through the GWMS during normal operation at rated power. Therefore, the licensee only presented the dose results for the release through the condenser. The control room was modeled as described below for the LOCA, with the exception that no credit is taken for control room emergency filtration system (CREFS) filters or charcoal beds. The staff finds that the licensee used analysis assumptions and methods that are consistent with RG 1.183.

The dose consequences and assumptions found acceptable to the NRC staff are presented in Tables 2.9.1 and 2.9.2. The EAB, LPZ, and control room doses estimated by HCGS for the CRDA were found to be within the regulatory dose acceptance criteria in SRP 15.0.1 and RG 1.183 and well within 10 CFR 50.67 TEDE reference values.

The NRC staff has evaluated the licensee's revised accident analyses for the radiological consequences of a CRDA and concludes that the licensee has adequately accounted for the effects of the proposed EPU on these analyses. The NRC staff further concludes that the plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of a postulated CRDA since the calculated TEDE doses at the EAB and the LPZ outer boundary are well within (25 percent of) the exposure guideline values in 10 CFR 50.67 and meet the regulatory dose acceptance criteria of 6.3 rem TEDE in RG 1.183 and SRP 15.0.1. The NRC staff also concludes that the control room meets the dose requirements of GDC-19 for DBAs. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to the radiological consequences of a CRDA.

2.9.2.2 Radiological Consequences of Instrument Line Pipe Break Accident

The licensee re-analyzed the ILPBA to include the EPU reactor coolant activity concentrations and TEDE dose criteria. The initial fission product concentration in the primary coolant corresponds to the maximum equilibrium values permitted by the TSs. The ILPBA is analyzed assuming the iodine concentration in the primary coolant at 4 μCi/g Dose Equivalent (DE) I-131. Of the 25,000 pounds of coolant released from the instrument line break, 6,000 pounds flashed to steam. All of the iodine in the coolant, which flashes to steam, is assumed to enter the steam phase with the coolant and 10 percent of the iodine remaining in the solution in the coolant becomes airborne. The activity released from the break is assumed to mix with 50 percent of the RB volume prior to being released to the environment via the Reactor Building Ventilation System (RBVS) through the South Plant Vent (SPV). The assumption of mixing in the RB is consistent with the HCGS current licensing basis. The post-ILPBA activity is assumed released instantaneously as a single puff and the CREFS charcoal filtration systems are not credited in the analysis. The post-ILPBA, EAB, LPZ, and control room (CR) doses are summarized in Table 2.9.1, which shows all doses are within their applicable regulatory limits.

The staff reviewed the information provided in the licensee's EPU submittal and supplements. PSEG's analysis used assumptions and inputs that follow the guidance in SRP 15.6.2, as adjusted by applicable guidance in RG 1.183 to calculate TEDE. Assumptions used by the licensee and evaluated by the NRC staff are listed in Table 2.9.3. The licensee's dose results are a small fraction of (10 percent) of 10 CFR 50.67 dose reference values (i.e. 2.5 rem TEDE) at the EAB and LPZ, and are within the dose criteria in GDC-19 of 5 rem TEDE.

The NRC staff has evaluated the licensee's revised accident analyses for the radiological consequences of ILPBA and concludes that the licensee has adequately accounted for the effects of the proposed EPU on these analyses. The NRC staff further concludes that the plant site and the dose-mitigating ESFs will remain acceptable with respect to the radiological consequences of a postulated failure outside the containment of a small line carrying reactor coolant since the calculated TEDE doses at the EAB and the LPZ outer boundary are a small fraction of the exposure guideline values of 10 CFR 50.67. The NRC staff also concludes that the control room meets the dose requirements of GDC-19 for DBAs. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to the radiological consequences of failures outside the containment of small lines connected to the primary coolant pressure boundary.

2.9.2.3 Radiological Consequences of Main Steamline Failure Outside Containment

The coolant and main steam source terms are affected by the EPU, as discussed above in Section 2.9.1. Therefore, the MSLB is analyzed using the uprated coolant and steam source terms, guidance in Appendix D of RG 1.183, and the TEDE dose criteria in Table 6 of RG 1.183. The accident considered is the complete severance of a MSL outside the primary containment. No fuel damage is projected to occur. The MSIVs are assumed to isolate the leak within 5.5 seconds. No other release mitigation is assumed. The analysis is performed for two activity release cases, based on the maximum equilibrium and pre-accident iodine spike concentrations of 0.2 µCi/gm and 4.0 µCi/gm DE I-131, respectively. These assumptions are in accordance with RG 1.183 and are consistent with the operation at EPU conditions. The licensee's assumptions on iodine speciation are taken from RG 1.183. The control room was modeled as described below for the LOCA, with the exception that no credit is taken for CREFS filters or charcoal beds. By the licensee's response dated March 22, 2007, the licensee stated that by not taking credit for CREFS filtration gives a bounding dose for the expected operation of the CREFS for the MSLB.

The dose consequences and assumptions found acceptable to the NRC staff are presented in Tables 2.9.1 and 2.9.4. The EAB, LPZ, and control room doses estimated by HCGS for the MSLB were found to be within the regulatory dose acceptance criteria in SRP 15.0.1 and RG 1.183 and well within 10 CFR 50.67 TEDE reference value.

The NRC staff has evaluated the licensee's revised accident analyses for the radiological consequences of an MSLB outside containment and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the analyses. The NRC staff further concludes that the plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of a postulated MSLB outside containment since the calculated TEDE doses at the EAB and the LPZ outer boundary do not exceed the exposure guideline values of 10 CFR 50.67 (assuming a pre-accident iodine spike) and are a small fraction (10 percent of) of the 10 CFR 50.67 values for an MSLB with the primary coolant at the maximum equilibrium concentration for continued full-power operation. The NRC staff also concludes that the control room meets the dose requirements of GDC-19 for DBAs. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to a postulated failure of an MSLB outside containment.

2.9.2.4 Radiological Consequences of a Design-Basis Loss-of-Coolant-Accident

To demonstrate the adequacy of the Hope Creek engineered safety feature (ESF) systems to mitigate the radiological consequences of design-basis LOCA, the licensee recalculated the offsite and control room radiological doses from a postulated LOCA at a reactor core power level of 4031 MWt, which is above the requested power increase level of 3840 MWt.

In its submittal, the licensee concluded that the existing Hope Creek ESF systems, with this license amendment, would still provide adequate assurance that the radiological consequences of a postulated LOCA at the EAB, in the LPZ, and in the control room would be within the dose criteria specified in 10 CFR 50.67. The licensee calculated the radiological consequences for the following three potential fission product release pathways after the postulated LOCA:

1. Containment leakage;
2. Post-LOCA leakage from ESF systems outside containment; and
3. Main steam isolation valve (MSIV) leakage.

These three potential fission product release pathways are evaluated in Sections 2.9.2.4.1, 2.9.2.4.2, and 2.9.2.4.3 of this SE.

Table 2.9.1 summarizes the results of the licensee's radiological consequence calculations, while Table 2.9.5 list the major parameters and assumptions used by the licensee in its radiological consequence calculations and by the staff in its confirmatory dose calculations.

2.9.2.4.1 Containment Leakage Pathway

The FRVS consists of two ESF subsystems, the FRVS vent system (FRVS-VS) and the FRVS recirculation system (FRVS-RS). The FRVS-VS processes and filters air from the containment before it is released to the environment. The FRVS-RS cleans contaminated air re-circulated through the RB. The licensee evaluated the radiological consequences resulting from containment leakage following a postulated design-basis LOCA at a reactor core power level of 4031 MWt. The licensee used a containment leak rate of 0.5 percent per day based on the allowable Hope Creek TS limit for the first 24 hours and a 0.25 percent per day leak rate for the remaining 29 days of the accident period, consistent with the guideline provided in RG 1.183 and as previously found acceptable in Amendment No. 134. The licensee also assumed that the source term in the primary containment mixes instantaneously and homogeneously throughout the free air volume of the primary containment. Hope Creek has a General Electric Mark 1 type containment. Because the RB is not maintained at a 0.25-inch water gauge negative pressure relative to adjacent areas during the first 375 seconds of the accident, the licensee assumed that all containment leakage is released unfiltered to the environment. After this initial 375-second period, the licensee assumed that primary containment leakage is mixed into 50 percent of the RB volume and then processed by the FRVS before being released to the environment. This was previously found acceptable in Amendment No. 134.

The FRVS-RS consists of six 25 percent capacity trains, each of which has a flow capacity of 30,000 cfm. Of the six trains, four are normally in operation, with a total combined flow capacity of 120,000 cfm. Therefore, the licensee assumed a combined containment air mixing flow rate of 108,000 cfm by four trains (90 percent of the rated capacity of each train, or 27,000 cfm each). The licensee did not credit any iodine removal by the charcoal absorbers in the FRVS-RS. The licensee assumed 99 percent efficiency aerosol iodine removal by the FRVS-RS HEPA filters. The filter efficiency is in accordance with RG 1.52.

The FRVS-VS is designed to exhaust sufficient air from the RB to maintain a negative pressure in that building and to remove airborne radioactive materials before discharging the air to the environment. The FRVS-VS takes suction only from the discharge duct of the FRVS-RS. The licensee assumed a RB air mixing efficiency of 50 percent. To simulate the 50 percent air mixing in the RB, the licensee doubled the FRVS-VS release rates to the environment. The licensee's evaluation of radiological consequences used 90 percent iodine removal efficiency by charcoal absorbers in the FRVS-VS. The licensee assumed 99 percent aerosol removal efficiency by the HEPA filters. The filter efficiency is in accordance with RG 1.52.

The licensee did not credit the safety-related drywell spray system for removal of fission products. Instead, the licensee modeled aerosol removal in the unsprayed area of the containment by natural deposition, using the Powers natural deposition model provided in the RADTRAD code choosing the 10th percentile uncertainty distribution. This was found acceptable in Amendment No. 134.

The radiological consequence contribution from this release pathway resulting from the postulated LOCA, as calculated by the licensee, is shown in Table 2.9.1. The overall radiological consequences from the combined contributions from all release pathways are evaluated in Section 2.9.2.4.6 of this SE.

2.9.2.4.2 Post-LOCA ESF System Leakage Pathway

With the exception of noble gases, the licensee assumed that all of the fission products that are released from the fuel to the containment instantaneously and homogeneously mix with the suppression pool water at the time of release from the core. Any water leakage from ESF components located outside the primary containment releases fission products during the recirculating phase of long-term core cooling after a postulated LOCA. In the Hope Creek UFSAR, the licensee estimated this leakage to be less than 1 gpm. The use of 1 gpm was approved by the NRC License Amendment No. 146. In addition, the licensee has in place a TS required program to monitor and control such leakage. The licensee used 2 gpm (two times design basis leakage value) in its dose calculation for the entire duration of the accident (i.e., 30 days) consistent with the guideline provided in RG 1.183.

The licensee assumed that 30 percent of the core iodine inventory mixes with the suppression pool water and circulates through the containment's external piping systems. The licensee also assumed that 10 percent of the iodine in the liquid leakage becomes airborne, and the airborne iodine is immediately released to the environment. In addition, the licensee assumed that radio iodine that is postulated to be available for release to the environment is 97 percent in elemental iodine form and 3 percent in organic iodine form. These assumptions are consistent with RG 1.183 and are, therefore, acceptable. The radiological consequence contribution from this release pathway resulting from the postulated LOCA, as calculated by the licensee, is shown in

Table 2.9.1. The overall radiological consequences from the combined contributions from all release pathways are discussed in Section 2.9.2.4.6 of this SE.

2.9.2.4.3 MSIV Leakage Pathway

Hope Creek has four MSLs, each of which has an inboard MSIV and an outboard MSIV. These valves isolate the RCS in the event of a break in a steam line outside the primary containment, a design-basis LOCA, or other events requiring containment isolation. The licensee assumed a double-guillotine pipe rupture in one of the four MSLs upstream of the inboard MSIV. A total of 250 standard cubic feet per hour (scfh, the TS limit) is assumed to occur in the following ways: 150 scfh through the broken steam line; 50 scfh through an intact steam line; the remaining 50 scfh through a second intact steam line; and no leakage from a third intact steam line. These leakage assumptions are the current licensing bases as approved in Hope Creek License Amendment No. 134.

In its dose calculation for this release pathway, the licensee used the model developed and used by the staff in its review of a similar license amendment request for Perry Nuclear Power Plant, as described in the staff's Technical Report, AEB-98-03, "Assessment of Radiological Consequences for the Perry Pilot Plant Application Using the Revised (NUREG-1465) Source Term," dated December 9, 1998. Although many of the systems at Perry Nuclear Power Plant and Hope Creek are of different designs, the aerosol deposition rates of fission products in the main steam system will be similar; therefore, the staff found in Amendment No.134 that the licensee did not make any changes to the use of the piping deposition model for the EPU reanalysis of the LOCA. The licensee credited element iodine removal in steam piping using the model previously found acceptable in Amendment No. 134. The EPU does not affect the inputs, assumptions, or methods previously found acceptable for iodine removal in steam piping.

The radiological consequence contribution from the MSIV leakage release pathway resulting from the postulated LOCA, as calculated by the licensee, is shown in Table 2.9.1. The overall radiological consequences from the combined contributions from all release pathways are discussed in Section 2.9.2.4.6 of this SE.

2.9.2.4.4 Control Room Model

The radioactivity from the above sources are assumed to be released into the atmosphere and transported to the CR air intake, where it may leak into the CR envelope or be filtered by the CR intake and recirculation filtration system and distributed in the CR envelope. There are four major radioactive sources, which contribute to the CR TEDE dose are:

1. Post-LOCA airborne activity inside the CR
2. Post-LOCA airborne cloud external shine to CR
3. Post-LOCA containment shine to CR
4. Post-LOCA CREF filter shine

Credit for ESF that mitigate airborne activity within the control room is taken for control room isolation/pressurization and intake and recirculation filtration. The control room design is often optimized for the DBA LOCA and the protection afforded for other accident sequences may not be as advantageous. In most designs, control room isolation is actuated by ESF signals or radiation monitors (RMs). In some cases, the ESF signal is effective only for selected accidents, placing reliance on the RMs. Several aspects of RMs can delay the isolation, including the delay for activity to build up to concentrations equivalent to the alarm setpoint and the effects of different radionuclide accident isotopic mixes on monitor response. The CR emergency filtration system is conservatively assumed to be initiated at 30 minutes after a LOCA, after the CR normal supply fan has been tripped. The CR unfiltered in leakage is conservatively assumed to be 500 cfm during the CREF transition period of 30 minutes after a LOCA. This was found acceptable in Amendment No. 134.

The radioactivity releases and radiations levels used for the control room dose are determined using the same source term, transport, and release assumptions used for determining the EAB and LPZ TEDE values. The staff finds that the licensee used analyses, assumptions, and methods that are consistent with RG 1.183.

2.9.2.4.5 Shine Dose

The radioactive plumes released from various post-LOCA sources are carried over the CR building, submerging the CR in the radioactive cloud. The CR operator is exposed to direct radiation from the radioactive cloud external to the CR structure. The review of control building concrete structure drawings indicate that the CR is surrounded by at least 2 feet 10.5 inches concrete shielding with a minimum distance of 29 feet from the least shielding person. The licensee states that this minimum-shielding configuration provides an adequate protection to the CR operator to reduce the CR operator external cloud dose to a negligible amount. This is consistent with the licensee’s current licensing basis.

The post-LOCA airborne activity in the containment is released into the RB via containment leakage through the penetrations and openings and gets uniformly distributed inside the RB. The airborne activity confined in the dome space of the RB contributes direct shine dose to the CR operator. The licensee stated that the combination of the concrete thickness of the containment building and the concrete shielding of the CR provides ample shielding to reduce the CR operator containment shine dose to an insignificant amount. This is consistent with the licensee’s current licensing basis.

The total integrated iodine and aerosol activities on the CR filters were calculated based on a CR unfiltered in-leakage of 1000 cfm and an ESF leakage of 10 gpm. The CR filter shine dose calculated for the current licensing basis LOCA dose calculation is negligible. In the revision of the LOCA dose calculation for the EPU, the CR unfiltered in-leakage and ESF leakage are reduced to 350 cfm and 1 gpm respectively. The licensee’s analysis indicates that the accumulation of iodine on the CREFS charcoal bed contributes the major shine dose. The activity accumulated on the charcoal filter and the resulting charcoal filter shine dose are functions of CR unfiltered in-leakage rate and source strength of the airborne activity. The reductions in the CR unfiltered in-leakage and ESF leakage will reduce the CR charcoal filter shine dose substantially, which will compensate for any increase in the airborne iodine activity due to deletion of the FRVS charcoal re-circulation filtration, reduction in the FRVS vent charcoal filter efficiency, and increase in the core uprated core inventory. Therefore, the previously calculated CR filter shine dose is judged to be bounding for the subject changes.

2.9.2.4.6 LOCA Conclusion

The licensee re-evaluated the radiological consequences resulting from the postulated LOCA using the AST and concluded that the radiological consequences at the EAB, LPZ and in the control room are within the dose criteria specified in 10 CFR 50.67. The staff has reviewed the licensee's evaluation. In performing this review, the staff relied upon information provided by the licensee; staff experience in performing similar reviews; and, where deemed necessary, on confirmatory calculations. The staff reviewed the methods, parameters, and assumptions that the licensee used in its radiological dose consequence analyses and finds that they are consistent with the conservative guidance provided in RG 1.183.

To verify the licensee's radiological consequence analyses, the staff performed its confirmatory radiological consequence dose calculation and found the staff's results are also within the dose criteria specified in 10 CFR 50.67. Although the staff performed its independent radiological consequence dose calculation as a means of confirming the licensee's results, the staff's acceptance is based on the licensee's analyses. The results of the licensee's radiological consequence dose calculation are provided in Table 2.9.1 and the major parameters and assumptions used by the licensee and the staff are listed in Table 2.9.5. The radiological consequences calculated by the licensee and by the staff for the EAB and at the LPZ, and in the control room are all within the dose criteria specified in 10 CFR 50.67 and are, therefore, acceptable.

The staff, therefore, concludes that the proposed EPU meets the relevant dose acceptance criteria and is, therefore, acceptable with the respect to the radiological consequences of DBAs.

2.9.2.5 Radiological Consequences of Fuel Handling Accidents

During refueling operations, the most restrictive DBA requiring containment operability is the FHA. The licensee re-analyzed the radiological consequences of a postulated FHA in the containment with no credit taken for containment isolation using the guidance provided in Appendix B RG 1.183, "Assumptions for Evaluating the Radiological Consequences of a Fuel Handling Accident." The FHA is postulated to occur as a consequence of a failure of the fuel assembly lifting mechanism, resulting in a drop of a raised fuel assembly onto stored fuel assemblies in the reactor core. The licensee assumed a total of 124 fuel rods are damaged. The fuel rod failure mechanism is described in the Hope Creek UFSAR Section 15.7.4. Because the EPU does not affect the postulated failure mechanism for this accident, the staff finds the assumption of 124 failed rods continues to be acceptable.

Instantaneous release of all noble gases and iodine vapors from the fuel rod gaps from the damaged fuel rods occurs as gas bubbles up through the water covering the fuel. All fission products reaching the RB atmosphere are released directly to the environment within 2 hours without filtration. The licensee concluded that the radiological consequences resulting from the postulated FHA in the containment with no credit taken for containment isolation are within the dose acceptance criteria specified in SRP 15.0.1, "Radiological Consequence Analyses Using ASTs," and GDC 19.

The licensee takes no credit for fission product removal by the RB FRVS-RS, the RB FRVS-VS, and CREFS. An effective overall decontamination factor of 200 for iodine is used, in the SFP water with minimum water depth of 23 feet consistent with the guidelines provided in RG 1.183. All fuel rods in two fuel assemblies with a radial power peaking factor of 1.75 are assumed damaged to the extent that the entire gap activity inventory of the damaged fuel rods is released instantaneously to the surrounding water.

The staff reviewed the licensee's methods, parameters, and assumptions used in its radiological dose consequence analyses and finds that they are consistent with the guidance provided in RG 1.183. The staff's acceptance is based on our review of the licensee's analyses. The results of the licensee's radiological consequence calculations are provided in Table 2.9.1 and the major parameters and assumptions used by the licensee and acceptable to the staff are listed in Table 2.9.6. The radiological consequences at the EAB, at the LPZ, and in the CR as calculated by the licensee are within the dose criterion specified in GDC 19 and meet the dose acceptance criteria specified in the SRP 15.0.1, and are, therefore, acceptable.

The NRC staff has evaluated the licensee's revised accident analyses for the radiological consequences of FHAs and concludes that the licensee has adequately accounted for the effects of the proposed EPU on these analyses. The NRC staff further concludes that the plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of a postulated FHA since the calculated TEDE doses at the EAB and the LPZ outer boundary are well within (25 percent of) the exposure guideline values of 10 CFR 50.67. The NRC staff also concludes that the control room meets the dose requirements of GDC-19 for DBAs. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to the radiological consequences of FHAs.

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 ESFs remain acceptable with respect to the radiological consequences of postulated DBAs since, as set forth above, the calculated TEDE at the EAB, at the LPZ outer boundary, and in the control room meet the exposure guideline values specified in 10 CFR 50.67 and GDC-19, as well as applicable acceptance criteria denoted in SRP Section 15.0.1. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to the radiological consequences of DBAs.

TABLE 2.9.1

Radiological Consequences
for
Postulated Design Basis LOCA
(rem TEDE)[(1)]

Release Pathway	EAB	LPZ	Control Room
CRDA	0.0292	0.00623	0.0137
Dose criteria [(2)]	2.5	2.5	5.0
ILPBA	0.0740	0.00741	0.324
Dose criteria [(3)]	2.5	2.5	5
MSLB			
4.0 µCi/gm DEI-131	0.942	0.0945	3.6
Dose criteria [(2)]	25	25	5
0.2 µCi/gm DEI-131	0.0561	0.00563	0.0181
Dose criteria [(2)]	2.5	2.5	5
LOCA			
Containment leak	0.373	0.162	1.05
ESF leak	0.191	0.0979	1.25
MSIV leak	2.63	0.456	2.13
CR Filter Shine	0.0	0.0	0.00246
Total	3.194	0.7159	4.43
Dose criteria [(2)]	25	25	5
Fuel Handling Accident	0.527	0.0527	3.31
Dose criteria [(3)]	6.3	6.3	5

(1) Rounded to two significant digits
(2) From 10 CFR 50.67
(3) From SRP 15.0.1

TABLE 2.9.2

Parameters and Assumptions Used in Radiological Consequence Calculations for a CRDA

Parameter	Value
Peaking factor	1.75
Fraction of core inventory in gap	
Noble gases	0.1
Iodine	0.1
Alkali metals	0.12
Amount of core with damaged fuel rods, percent	1.8
Damaged rods that fail, percent	0.77
Melted fuel release fraction to vessel	
Noble gases	1.0
Iodine	0.5
Alkali metals	0.25
Fraction of activity released to vessel that enters main condenser	
Noble gases	1.0
Iodine	0.1
Others	0.01
Fraction of activity released from main condenser	
Noble gases	1.0
Iodine	0.1
Others	0.01
Release rate from main condenser, percent/day	1
Release duration, hours	24
CREFS initiation	Not credited
Control room unfiltered intake, cfm	350
Control room χ/Q	Table 2.9.7

TABLE 2.9.3

Parameters and Assumptions Used in Radiological Consequence Calculations for an ILPBA

Parameter	Value
Power level, MWt	4,031
Maximum reactor coolant iodine activity concentration, μCi/gm	4.0
Mass of total coolant released from break, lb	25,000
Reactor building volume, ft^3	4.00E+06
Iodine chemical form, %	
Elemental	97
Organic	3
Type of release to the atmosphere	Ground level release from FRVS vent
CREFS initiation	Not credited
Control room unfiltered intake rate, cfm	350
Control room X/Qs	Table 2.9.7

TABLE 2.9.4

Parameters and Assumptions Used in Radiological Consequence Calculations for an MSLB

Parameter	Value
Liquid coolant release discharged mass, lb	140,000
MSIV closure time, sec	5.5
Reactor coolant activity, μCi/gm DE I-131	
Normal	0.2
Spike	4.0
Radioactivity release rate to environment	Instantaneous
Control room occupancy factor	1
CREFS initiation	Not credited
Control room unfiltered intake rate, cfm	350
Control room X/Qs	Table 2.9.7

TABLE 2.9.5

Parameters and Assumptions Used in Radiological Consequence Calculations for a LOCA

Parameter	Value
Reactor power	4,031 MWt
Drywell air volume	1.69E+5 ft^3
Containment air volume	3.06E+5 ft^3
Reactor building air volume	4.0E+6 ft^3
Containment leak rate to environment	
0 - 24 hours	0.5% per day
1 - 30 days	0.25% per day
Reactor building pressure drawdown time	375 seconds
Aerosol deposition rate in drywell	10 percentile in RADTRAD
Reactor building mixing efficiency	50%
FRVS vent exhaust filter efficiencies	
Elemental iodine	90%
Organic iodine	90%
Aerosol (particulate)	99%
FRVS recirculation filter efficiencies	
Elemental iodine	Not credited
Organic iodine	Not credited
Aerosol (particulate)	99%
FRVS recirculation flow rate	1.08E+5 cfm
ECCS leak rate	1 gpm
ECCS iodine partition factor	10%
ECCS leak initiation time	0 minutes
Sump volume	1.18E+5 ft^3
MSIV leak rate	
All four lines	250 scfh
Line with MSIV failed	150 scfh
First intact line	50 scfh
Second intact line	50 scfh
Aerosol settling velocity on main steamlines	8.1E-4 meters/second
Aerosol settling area (well-mixed region volumes)	
MSIV faulted line	1398 ft^3
MSIV intact lines	1476 ft^3
Control room volume	8.5E+4 ft^3
CREFS outside air intake flow	1000 cfm
CREFS recirculation flow	2600 cfm
Control room isolation time	30 minutes
Unfiltered air in leakage rate into control room	
0 to 30 minutes	500 cfm
30 minutes to 30 days	350 cfm
CREFS filter efficiencies	
Elemental iodine	99%
Organic iodine	99%
Aerosol (particulate)	99%
Control X/Qs	Table 2.9.7

Table 2.9.6

Parameters and Assumptions Used in Radiological Consequence Calculations FHA

Parameter	Value
Reactor power	4,031 MWt
Radial peaking factor	1.75
Fission product decay period	24 hours
Number of fuel rod damaged	124
Fuel pool water depth	23 ft
Fuel gap fission product inventory	
Noble gases excluding Kr-85	5%
Kr-85	10%
I-131	8%
Alkali metals	12%
Fuel pool decontamination factors	
Iodine	200
Noble gases	1
Duration of accident	2 hours
Fission product release point	ground level release from reactor building truck bay door
Control room volume	8.5E+4 ft^3
Control room isolation	Not isolated
Control room normal flow rate	
0 to 720 hours	3300 cfm
Control room X/Qs	Table 2.9.7

TABLE 2.9.7

Hope Creek Meteorological Data

EAB

Time	X/Q (sec/m^3)
0 - 2 hrs	1.9 E-04

LPZ

Time	X/Q (sec/m^3)
0 - 2 hrs	1.9 E-05
2 - 4 hrs	1.2 E-05
4 - 8 hrs	8.0 E-06
8 - 24 hrs	4.0 E-06
1 - 4 days	1.7 E-06
4 - 30 days	4.7 E-07

Control Room from Reactor Building Truck Bay Door (FHA)

Time	X/Q (sec/m^3)
0 - 2 hrs	1.39 E-03
2 - 8 hrs	1.17 E-03
8 - 24 hrs	4.76 E-04
1 - 4 days	3.20 E-04
4 - 30 days	2.60 E-04

Control Room from Turbine Building Louvers (CRDA & Post-LOCA MSIV Leakage)

Time	X/Q (sec/m^3)
0 - 2 hrs	6.17 E-04
2 - 8 hrs	4.00 E-04
8 - 24 hrs	1.44 E-04
1 - 4 days	1.00 E-04
4 - 30 days	7.49 E-05

Control Room from FRVS Release (ILPBA & Post-LOCA Containment & ESF Leakages)

Time	X/Q (sec/m^3)
0 - 2 hrs	1.25 E-03
2 - 8 hrs	8.09 E-04
8 - 24 hrs	3.04 E-04
1 - 4 days	2.10 E-04
4 - 30 days	1.59 E-04

TABLE 2.9.7 Continued

Hope Creek Meteorological Data

Control Room from Steam Blowout Panel Release (MSLBA)

Time	X/Q (sec/m^3)
0 - 2 hrs	1.20 E-03
2 - 8 hrs	8.16 E-04
8 - 24 hrs	3.08 E-04
1 - 4 days	2.14 E-04
4 - 30 days	1.63 E-04

2.10 Health Physics

2.10.1 Occupational and Public Radiation Doses

Regulatory Evaluation

The NRC staff conducted its review in this area to ascertain what overall effects the proposed EPU will have on both occupational and public radiation doses and to determine 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 how this may affect plant area dose rates, plant radiation zones, and plant area accessibility. The NRC staff evaluated how personnel doses needed to access plant vital areas following an accident are affected. The NRC staff considered the effects of the proposed EPU on N^{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's acceptance criteria for occupational and public radiation doses are based on Title 10 of the *Code of Federal Regulations* Part 20 (10 CFR 20), Appendix I of 10 CFR 50, and GDC 19 to Appendix A of 10 CFR 50 (GDC-19). Specific review criteria are contained in SRP Sections 12.2, 12.3,12.4, and 12.5, NUREG-0737, item II.B.2, and other guidance provided in Matrix 10 of RS-001.

Technical Evaluation

Source Terms

The EPU maximum authorized power level of 3840 MWt represents a 16.6 percent increase in power compared to the 3293 MWt OLTP at Hope Creek. However, it is a 15 percent increase from their CLTP level of 3339 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 occurring in 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 non-volatile fission products, actinides, and corrosion and wear products in the **[[** **]]**. However, the increase in steam flow is expected to result in a small percentage of moisture carryover resulting in the movement of these products to other areas of the plant resulting in increased dose rates in these areas. Although there are increases in dose rates, 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 steam flow; therefore, the concentration of these materials in the steam line remains constant. Although the EPU will result in an increase in the rate these materials are introduced into the Main Condenser and Off Gas systems, these expected increases continue to be within the design margins of the Off Gas system.

For the short lived activities, the most significant is N^{16}, the decreased transit (and decay) time in the MSL and the increased mass flow of the steam results in a larger increase in these activities in the major turbine building components. Based on the change in travel time of the steam to travel from the RPV nozzle to the steam components, the licensee estimates that the post-EPU N^{16} source strength for a 15 percent increase in steam flow is expected to increase radiation levels due to N^{16} concentration at steam turbine components by approximately 16 percent for operation at 3840 MWt.

Radiation Protection Design Features

Occupational and onsite radiation exposures.

The 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. This increase, however, is bounded by the existing safety margins of the design basis sources. Since the reactor vessel is inaccessible to plant personnel during operation and due to the design of the shielding and containment surrounding the reactor vessel, an approximate increase of 15 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 16 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 (i.e., 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, plant area radiation and process monitors are used to monitor radiation levels at 90 percent and 100 percent of CLTP and at 2.5 percent reactor power intervals above CLTP. In addition, as part of the ascension test plan, normally accessible areas adjacent to steam affected areas in the Turbine and RBs and Radwaste area of the Auxiliary Building will be surveyed at specific intervals of reactor power. Compliance with existing radiation postings will be verified during these surveys.

Operating at a 15 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 has adopted the AST methodology which was approved by the NRC on October 3, 2001.[264] The licensee calculated estimated doses based on the AST methodology for operators accessing and performing necessary functions in vital areas of the plant during postulated accident conditions. The result of these calculations indicate that the highest calculated post-accident vital area worker dose for personnel performing required post-LOCA vital area duties in the plant is less than 90 mrem, which is below the dose criteria of 5 rem in GDC-19.

Therefore, following implementation of this EPU, Hope Creek will continue to meet its design basis in terms of radiation shielding, in accordance with the criteria in SRP section 12.4., and the requirements of 10 CFR 50, 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 Hope Creek 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 result in a 15 percent increase in gaseous effluents released from the plant during normal operations. This increase is a minor contribution to the radiation exposure to the public. The nominal annual public dose from plant gaseous effluents for Hope Creek is approximately 1.83×10^{-3} mrem. A 15 percent increase of this nominal dose is still well within the 10 mrem per year dose criteria in 10 CFR 50, Appendix I.

Skyshine is a physical phenomena where N^{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 N^{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 stress-corrosion cracking (SCC) significantly increases the fraction of N^{16} in the reactor water that is released into the steam during power operations. For post-EPU conditions, the licensee performed calculations based on design basis sources including the effect of HWC and modeling of onsite radiation sources that contribute to offsite doses. The dose to the highest exposed member of the public (individual continuously present at the east site boundary) was calculated to be 9.3 mrem per year. This is within the 10 mrem per year dose criteria in 10 CFR 50, Appendix I and is well within the 100 mrem per year dose criteria in 10 CFR 20.

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[264] ADAMS Accession No. ML012600176

This EPU will result in increased generation of liquid waste. The increased condensate feed flow results in faster loading of the condensate demineralizers. This higher feed flow introduces more impurities in the reactor coolant resulting in faster loading of the RWCU system demineralizers. The demineralizers in both these systems will therefore require more frequent backwashing. The licensee has estimated that these more frequent backwashes will increase the volume of liquid waste by 2.2 percent. Since 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, the staff finds this acceptable.

Operational Radiation Protection Programs

The increased production of non-volatile fission products, actinides, and corrosion and wear products in the reactor coolant may result in proportionally higher plate-out 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 Hope Creek (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 licensees ability to maintain occupational and public radiation doses resulting from plant operation to with the applicable limits in 10 CFR 20 and ALARA.

Conclusion

The NRC staff has reviewed the licensee’s assessment of the effects of the proposed EPU on radiation source terms and plant radiation levels. The NRC staff concludes that the licensee has taken the necessary steps to ensure that any increases in radiation doses will be maintained ALARA. The NRC staff further concludes that the proposed EPU meets the requirements of 10 CFR 20, Appendix I to 10 CFR 50, 10 CFR 50.34(f)(2)(vii) (NUREG-0737), and 10 CFR 50, GDC-19. Therefore, the NRC staff finds the licensee’s proposed EPU acceptable with respect to radiation protection and ensuring that occupational radiation exposures will be maintained ALARA.

2.11 Human Performance

2.11.1 Human Factors

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 human factors evaluation was conducted to ensure that operator performance would not be adversely affected as a result of system and procedure changes made to implement the proposed EPU. The NRC staff's review covered changes to operator actions, human-system interfaces, and procedures and training needed for the proposed EPU. The NRC's acceptance criteria for human factors are based on GDC 19, 10 CFR 50.120, 10 CFR Part 55, and the guidance in GL 82-33. Specific review criteria are contained in the NUREG-0800 (Rev. 1) SRP Sections 13.2.1, 13.2.2, 13.5.2.1, and Chapter 18.0.

Technical Evaluation

Changes in Emergency and Abnormal Operating Procedures

In its response to the staff's RAI (March 13, 2007,)[265] PSEG stated that the EPU will require a revision of operating procedures including the EOPs and the abnormal operating procedures (AOPs). The operating procedures affected by the EPU LAR will be revised in accordance with the PSEG plant procedure control and training processes. The operating procedure changes include modifications required for some parameter thresholds and graphs, which depend on the power and decay heat levels, as well as changes in setpoints. A summary of the changes to the AOPs and EOPs is included in the licensee's response to the staff's RAI on March 13, 2007.

PSEG also plans to update the Hope Creek EOPs and Severe Accident Guidelines (SAGs) to incorporate Revision 2 of the BWROG EPGs/SAGs when the EPU is implemented.

The changes to the EOPs and AOPs include no new manual actions due to the EPU. The post-EPU manual actions are those currently required by existing operating procedures and are the same as the manual actions in the current FSAR. The licensee stated that there is no effect on these manual actions and the licensee stated that there is sufficient time available for operators to take the actions due to the EPU credited in the UFSAR.

Overall, the licensee indicated that the changes due to the EPU do not result in new procedures or changes in the operating and accident mitigation philosophies. The EOPs, AOPs, and SAGs will be revised to reflect the TS setpoints and other plant parameter changes related to the EPU. In addition, the licensee committed to provide operator training modified to incorporate all procedural changes related to the EPU prior to implementation. Therefore, the staff finds the licensee's proposed changes in this area to be acceptable.

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[265] PSEG letter (LR-N07-0035) to NRC dated March 13, 2007, "Response to Request for Additional Information Request for License Amendment - Extended Power Uprate" ADAMS Accession No. ML070790508

Changes to Operator Actions Sensitive to EPU

PSEG stated that there are no changes in Hope Creek's EOPs and AOPs that would involve new operator actions or changes to existing operator actions due to the EPU. PSEG stated that there is sufficient time available for manual actions credited in the Hope Creek analysis after EPU implementation. The outcome of the EPU implementation will be an increase in the amount of time required to bring the plant to cold shutdown status. However, this does not change the amount of time required for the operators to complete the actions credited in the UFSAR.

Based on the licensee's statements regarding the operator actions and the respective response and availability times, the NRC staff determined that there is reasonable assurance that the PSEG operators would continue to accomplish the operator actions credited in the Hope Creek safety analysis.

Changes to Control Room Controls, Displays and Alarms

In the RAI response (March 13, 2007)[266] PSEG stated that there are minimal changes to the human machine interfaces that will affect the operators' ability to interpret, read, or visually identify the information required from the instrumentation. While the changes made to the control room due to the EPU are minimal, all planned changes will be made through the design change process (DCP). This process includes a human factors engineering review and an impact review by operations and training personnel. The results of these reviews will be incorporated into the change package. Verification of successful completion of operator training is required as part of the DCP. Prior to EPU implementation, the operator training and requirements specific to the EPU will be identified, tracked, and used to update the operator aids, charts, and the plant-referenced simulator.

The purpose of this section is to assure that the licensee has adequately considered the equipment changes resulting from the EPU that affect the operators' ability to perform required functions. The NRC staff finds the proposed changes acceptable based upon the licensee implementing its DCP to address the EPU-related changes in the control room and the corresponding operator training and simulator modifications prior to EPU implementation.

Changes on the Safety Parameter Display System (SPDS)

PSEG stated that there are no changes to the method used to display the information. Minor re-scaling changes will be made to the input/output FW parameters to support the new span required by the EPU. The SPDS also provides a procedure-based display concept to support the Hope Creek EOPs. The following displays will be revised to reflect changes due to EPU conditions:

- Pressure Suppression Pressure Curve
- Heat Capacity Temperature Limit (HCTL) Curve
- Drywell Spray Initiation Pressure Limit Curve
- Power to Flow Map

[266] PSEG letter (LR-N07-0035) to NRC dated March 13, 2007, "Response to Request for Additional Information Request for License Amendment - Extended Power Uprate" ADAMS Accession No. ML070790508

The staff finds the proposed changes to the SPDS to be acceptable.

Changes to the Operator Training Program and the Control Room Simulator

The licensee stated that the training required to support changes required for EPU conditions will be conducted prior to plant operation at EPU conditions. The training consists of combined classroom and simulator training. As stated previously, the operator training will include operating procedures, abnormal and emergence procedures, aids, and charts using the training simulator modified for EPU conditions. The classroom training will cover changes to parameters, setpoints, scales, procedures, systems, and EPU test procedures.
The updates to the plant-referenced simulator include the BOP model, turbine, digital electro-hydraulic controls, and core model. The licensee stated that these changes to the simulator have been completed and are included in the training for EPU conditions to be completed prior to EPU implementation. Other minor changes to the simulator to be completed include changes to the SPDS, meter scaling, and the digital Feedwater control system (FWCS). These changes are scheduled for after EPU implementation, but are included in classroom operator training prior to EPU implementation.

PSEG commits to validate and verify simulator performance by conducting tests and evaluating the results against the predicted performance based on design and engineering analysis data as required by ANSI/ANS-3.5-1993, "Nuclear Power Plant Simulators for Use in Operator Training and Examination." PSEG further commits to comparing plant data gathered from the tests to the simulator data as required by ANSI/ANS-3.5-1993, Section 4.4.1. The test includes a demonstration that the simulator represents the plant to the scope required by Sections 3 and 4 of ANSI/ANS 3.5 1993.

The staff is satisfied that, based on the above commitments, the licensee has developed a satisfactory training program, including simulator training, for the proposed EPU.

Conclusion

The NRC staff has reviewed the licensee's submittal describing their identified changes to operator actions, human-system interfaces, procedures, and training required for the proposed EPU and concludes that: (1) the licensee has appropriately accounted for the effects of the proposed EPU on the procedures; and (2) taken appropriate actions to ensure adequate operator training addressing the changed conditions due to the EPU. 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 EPU. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to the human factors aspects of the required system changes.

2.12 Power Ascension and Testing Plan

Regulatory Evaluation

The purpose of the EPU test program is to demonstrate 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) transient testing necessary to demonstrate that plant equipment will perform satisfactorily at the proposed increased maximum licensed thermal power level; and (3) the test program's conformance with applicable regulations.

The NRC's acceptance criteria for the proposed EPU test program are based on 10 CFR Part 50, Appendix B, Criterion XI, which requires establishment of a test program to demonstrate that SSCs will perform satisfactorily in service. Additionally, specific review criteria are contained in NUREG-0800, Standard Review Plan (SRP) 14.2.1, "Generic Guidelines for EPU Testing Programs." The staff's review focused on PSEG adequately addressing the guidance described in the SRP. PSEG's proposed power ascension and test plan (PATP) follows the guidelines contained in NRC-approved GE Nuclear Energy Licensing Topical Reports (LTRs) which the staff determined to be an acceptable methodology for licensees requesting EPUs.

Technical Evaluation

SRP 14.2.1 Section III.A
Comparison of Proposed EPU Test Program to the Initial Plant Test Program

SRP 14.2.1 Section III.A, specifies the guidance and acceptance criteria which the licensee should use to compare the proposed EPU testing program to the original power-ascension test program performed during initial plant licensing. The scope of this comparison should include: 1) all initial power-ascension tests performed at a power level of equal to or greater than 80 percent of the OLTP level; and 2) initial test program tests performed at lower power levels if the EPU would invalidate the test results. The licensee shall either repeat initial power-ascension tests within the scope of this comparison or adequately justify proposed test deviations. The following specific criteria should be identified in the EPU test program:

- all power-ascension tests initially performed at a power level of equal to or greater than 80 percent of the 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; and,
- differences between the proposed EPU power-ascension test program and the portions of the initial test program identified by the previous criteria.

The staff reviewed Section 14 of the HCGS UFSAR, "Construction Verification, Preoperational, and Power Test Program," dated April 11, 1988, which presented a general purpose, description, and acceptance criteria of the initial startup testing. Additional information was reviewed by the staff which described the startup and power test program performed to demonstrate that the plant is capable of operating safely and satisfactorily. The staff also reviewed EPU test plan information, applicable sections of TSs, and the following information provided to the staff:

1. HCGS UFSAR, Section 14.2.12.3, "Startup Test Procedures," which provided an overview test objective, method and acceptance criteria associated with the initial power ascension test program from initial fuel loading through 100% power.

2. Attachment 5 to PSEG letter LR-N06-0286,[267] dated September 18, 2006, "List of Completed and Planned Modifications," provided a listing of completed and planned modifications necessary to support EPU.

3. Attachment 12 to PSEG letter LR-N06-0286, dated September 18, 2006, "NEDO-3076, Revision 2, "Safety Analysis Report for Hope Creek Constant Pressure Power Uprate," the Power Uprate Safety Analysis report (PUSAR). The PUSAR is a summary of the results of the safety analyses performed for the HCGS.

4. Attachment 16 to PSEG letter LR-N05-0258,[268] dated November 7, 2005, "Transient Testing," provided a justification for not performing large transient testing requiring an automatic scram from high power (e.g., main steam isolation valve closure).

5. Attachment 10 to PSEG's original request for license amendment, "RS-001 Review Matrix," provides a markup of the review matrices contained in the NRC's "Review Standard for Extended Power Uprates," (RS-001) with cross-references to the HCGS PUSAR and other documents submitted in support of this request.

6. Attachment 23 to PSEG letter LR-N06-0286, dated September 18, 2006, "EPU Power Ascension Test Plan Overview," provides an overview of the power ascension and test plan (PATP) for the HCGS.

The staff found that all transient tests described in the initial startup test program, as derived from UFSAR Paragraph 14.2, were listed in Section 1.0 of PSEG Attachment 16. PSEG provided a table listing these tests which were performed initially at greater than 80 percent OLTP, as detailed in Chapter 14 of the HCGS UFSAR. The tests included closure of all MSIVs at 99.6 percent power level (UFSAR Paragraph 12.3.21.3b) and a TT/generator load rejection test performed at 97 percent power (UFSAR Paragraph 12.3.23.3). These tests follow the tests described in Attachment 2 of SRP 14.2.1.

PSEG's PATP does not include performing large transient testing, specifically a MSIV closure test and a generator load rejection test at full-EPU power level. The justification for not performing such tests was presented by PSEG in Attachment 16, "Transient Testing," of their application. Attachment 23, "EPU Power Ascension Test Plan Overview," provides an overview of the PATP which covers power ascension up to the full 115 percent EPU condition to verify acceptable performance. The attachment also provides a comparison to the HCGS startup test program. This issue is further discussed in *"SRP 14.2.1 Section III.C"* of this SE.

[267] ADAMS Accession No. ML062680451
[268] ADAMS Accession No. ML053200202

The PATP is primarily an initial power ascension test plan designed to assess steam dryer and selected piping system performance from 100 percent CLTP to 115 percent CLTP and also to perform confirmatory inspections for a period of time following initial and continued operation at EPU levels. Testing will be performed in accordance with the TSs and applicable procedures on instrumentation re-calibrated to EPU conditions. Steady-state data will be taken during power ascension and continuing at each EPU power increase increment. EPU power increases above 100 percent CLTP will be achieved in a series of 2.5 percent power step increases and holds at plateaus corresponding to 5 percent increments above CLTP. Steady-state and transient data will be taken at each step. Power ascension will occur over a period of time with gradual increases in power, hold periods, and engineering analysis of monitored data that must be approved by station management prior to subsequent power increases. PSEG is also performing post-modification testing, calibration, normal surveillance, and power ascension testing, as required, to ensure that systems will operate in accordance with their design requirements.

With the exception of the staff's review of PSEG's justification for not performing large transient testing, which is discussed below, the staff concludes through comparison of the documents referenced above, including a review of the initial startup and test program described in Section 14.2 of the HCGS 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 staff also concluded that with respect to the program implementation methodology, the PSEG power ascension test program is acceptable and in conformance with the applicable regulations, and addressed the staff guidance and review criteria described in SRP 14.2.1.

SRP 14.2.1 Section III.B
Post Modification Testing Requirements for Functions Important to Safety Impacted by EPU-Related Plant Modifications

Section III.B of SRP 14.2.1 specifies the guidance and acceptance criteria which the licensee should use to assess the aggregate impact of EPU plant modifications, setpoint adjustments, and parameter changes that could adversely impact the dynamic response of the plant to AOO. AOOs include those conditions of normal operation that are expected to occur one or more times during the life of the plant and include events such as loss of all offsite power, tripping of the main TG set, and loss of power to all reactor coolant pumps. The EPU test program should adequately demonstrate the performance of SSCs important to safety that meet all of the following criteria: (1) the performance of the SSC is impacted by EPU-related modifications; (2) the SSC is used to mitigate an AOOs described in the plant-specific design basis; and, (3) involves the integrated response of multiple SSCs.

The following should be identified in the EPU test program as it pertains to the above paragraph:

- plant modifications and setpoint adjustments necessary to support operation at EPU conditions, and

- changes in plant operating parameters (such as reactor coolant temperature, pressure, T_{ave}, reactor pressure, flow, etc.) resulting from operation at EPU conditions.

The staff reviewed Attachment 5 to the application, “List of Completed and Planned Modifications,” which described the planned modifications necessary to support the EPU which will be implemented prior to restart from RFO RF14, currently scheduled for fall 2007. The staff also reviewed Attachment 6 which described PSEG’s aggregate impact analysis of the modifications necessary to support CPPU. Post modification testing associated with the modifications proposed by PSEG includes functional performance checks, component performance measurements, equipment calibrations, physical and NDE inspections and pressure drop measurements at full flow conditions. PSEG stated that plant modifications, set-point adjustments and parameter changes will be demonstrated by a test program established for BWR EPU in accordance with startup test specifications as described in PUSAR Section 10.4. 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 CPPU.

PSEG stated that most modifications will have been implemented for one to two full operating cycles in advance of CPPU implementation and therefore, the aggregate impact of these improvements, if any, should not be a factor in power ascension to EPU. Some of the planned modifications considered by PSEG for the HCGS include the HP main turbine, LP turbine, turbine moisture separator, main generator system and steam dryer modifications. The modifications are being implemented in accordance with the requirements of 10 CFR 50.59.

With the exception of the staff’s review of PSEG’s justification for not performing large transient testing discussed below, the staff concludes that the testing program proposed by PSEG adequately demonstrates that EPU related modifications will be adequately implemented. Specifically, the staff concludes that based on a review of PSEG’s listing of completed and planned modifications, including post maintenance testing associated with these modifications, the proposed EPU test program should adequately demonstrate the performance of SSCs important to safety and included those SSCs: (1) impacted by EPU-related modifications; (2) used to mitigate an AOO described in the plant design basis; and (3) supported a function that relied on integrated operation of multiple systems and components. The staff also concludes that the proposed PATP adequately identified plant modifications necessary to support operation at the uprated power level and complies with the EPU review criteria established in Section III.B of SRP 14.2.1.

SRP 14.2.1 Section III.C
Use of Evaluation To Justify Elimination of Power-Ascension Tests

Section III.C. of SRP 14.2.1 specifies the guidance and acceptance criteria the licensee should use to provide justification for a test program that does not include all of the power-ascension testing that would normally be performed, provided that proposed exceptions are adequately justified in accordance with the criteria provided in Section III.C.2. Each secondary review branch will verify and document 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 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 and EOPs,
- margin reduction in safety analysis results for AOOs,
- guidance contained in vendor topical reports, and
- risk implications.

The 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 prior to extended operation at the requested EPU power level. The 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 of SRP 14.2.1 that would normally be performed, provided that proposed exceptions are adequately justified in accordance with the criteria provided in SRP 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 and EOPs, and adverse operating experience from previous EPUs, should be considered and addressed.

The PATP is relied upon as a quality check to: (a) confirm that analyses and any modifications and adjustments that are necessary for proposed EPUs have been properly implemented, and (b) benchmark the analyses against the actual integrated performance of the plant. This is consistent with 10 CFR Part 50, Appendix B, which states that design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate calculational methods, or by the performance of a suitable testing program; and requires that design changes be subject to design control measures commensurate with those applied to the original plant design, which includes power ascension testing.

SRP 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 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 staff reviewed the applicant's justification for not performing certain original startup tests against the review criteria established in SRP 14.2.1. PSEG presented its justification in Attachment 16 of their application for EPU. The PSEG PATP does not include all of the power ascension testing that would typically be performed during initial startup of a new plant. PSEG provided a detailed discussion of the basis for elimination of certain large transient testing (e.g., MSIV full closure and generator load rejection) pursuant to the staff review criteria established in Section III.C.2 of SRP 14.2.1. The following large transient tests were performed during initial startup as discussed in the HCGS UFSAR:

Closure of All MSIVs.

As documented in Section 14.2.12.3.21.3b of the HCGS UFSAR, this initial startup test was a simultaneous full closure of all MSIVs and was performed at 99.6-percent (3280 MWt) of rated reactor thermal power (3292 MWt). The test objectives were to functionally check the MSIVs at selected power levels, determine isolation valves' closure times, and to determine reactor transient behavior during and following simultaneous closure of all MSIVs. No MSIV full-closure events, intentional or unintentional, have been recorded since the plant startup test. Consequently, initial startup testing at 3280 MWt is the highest reactor power level at which a full MSIV closure has occurred at the HCGS.

PSEG reported in the EPU application that the MSIV full closure event was analyzed at a reactor power level of 102-percent of 3840 MWt (15-percent above CLTP, and 16.6-percent above OLTP). The staff reviewed the results which were presented in Section 9.1.1 of the PUSAR.

Turbine Trip/Generator Load Rejection

In accordance with Section 14.2.12.3.23.3 of the HCGS UFSAR, this initial startup test was performed in December 1986 at 97-percent of rated thermal power (3194 MWt) to demonstrate the proper response of the reactor and its control systems following trips of the turbine and generator. During the test, the TSVs are tripped at selected reactor power levels and simultaneous opening of the main generator output breakers. PSEG stated that all acceptance criteria were satisfied.

With respect to the review criteria established in SRP 14.2.1, Section III.C.2, PSEG cited industry events that occurred at greater than original power levels at stations of similar design as HCGS (BWR-4 with Mark I containments) which resulted in examples of plant response to MSIV closure and load reject events. The staff reviewed the licensee event reports (LERs), associated with the following examples, and the staff identified that all systems functioned as expected.

PSEG cited several events at Plant Hatch Unit 1 which included a turbine trip and a generator load reject event subsequent to its uprate, as reported in LERs 2000-004 and 2001-002. According to the LERs, the behavior of the primary safety systems was as expected. Plant Hatch Unit 2 also experienced an unplanned event that resulted in a generator load reject from 98 percent of rated power in May 1999. The staff reviewed the LER and the staff identified that all systems functioned as expected and per their design given the water level and pressure transients caused by the turbine trip and reactor scram. Both units at Plant Hatch were previously granted an EPU by the NRC without the requirement to perform large transient testing.

Another similar BWR/4 plant with a Mark I containment is Brunswick Units 1 and 2 which were licensed to 120 percent OLTP. An unplanned event at Unit 2 resulted in a generator trip at 115.2 percent OLTP (96 percent of uprated thermal power) in 2003. As noted by the staff in LER 2003-04, plant systems responded as designed to the transient and the event was fully bounded by the analyses in Chapter 15 of the FSAR. On January 12, 2003, Unit 1 experienced a turbine trip (TT) at 94 percent rated thermal power as reported in LER 2003-01. The required equipment responded as designed and the Group 2 and 6 valves isolated. The LER safety assessment, reviewed by the staff, stated that the reactor trip is an anticipated operational occurrence bounded by the existing safety analyses; that the operation of the plant was within the design limits; and the affected systems responded as designed.

Another factor used by PSEG to justify not performing large transient testing were actual plant transients experienced at the HCGS. PSEG stated that since initial plant startup in 1986, HCGS has experienced a number of TT or generator load reject events. Nine events involving TTs or generator load rejections were referenced in Section 3.5 of Attachment 16 to the application which covered the time period from 1986 through 1994.

PSEG stated that information obtained regarding testing and responses to unplanned transients for Hatch Units 1 and 2 and Brunswick Units 1 and 2 during post-EPU operation have shown that the plant response was as expected and in accordance with their design features. PSEG also addressed several of the review criteria in SRP 14.2.1, Section III.C.2, by stating that no modifications are to be performed as part of EPU implementation that would cause HCGS to behave differently from previous operating experience for an MSIV closure event, and that the plant response at CPPU conditions is expected to be similar to the documented response during initial startup testing. PSEG also stated that the MSIV full closure event was analyzed at a reactor power level of 102 percent of 3840 MWt (full-EPU maximum power level), and the generator load reject event was analyzed at a reactor power level of 3840 MWt. PSEG presented the results in Section 9.1.1 of the PUSAR. PSEG stated that no MSIV full-closure events, intentional or unintentional, have been recorded at the HCGS since the initial plant startup test in 1986.

Plant Transient Evaluation

Transient experience at high power and for a wide range of operating power levels at operating BWR plants have shown an acceptable correlation of the plant transient data to the predicted response. The operating history of HCGS demonstrates that previous transient events from full power are within expected peak limiting values. The transient analysis performed for the HCGS CPPU demonstrated that all safety criteria are met and that this uprate did not cause any previous non-limiting events to become limiting. This issue is further discussed in Section 2.8.5 of the staff's SE.

Based on the similarity of plants, past transient testing, past analyses, and the evaluation of test results, the effects of the CPPU rated thermal power level can be analytically determined on a plant-specific basis. No new design functions that would necessitate modifications and no large transient testing validation were required of safety related systems for the CPPU. The instrument setpoints that were changed do not contribute to the response to large transient events. No physical modification or setpoint changes were made to the SRVs and no new systems or features were installed for mitigation of rapid pressurization AOOs for this CPPU. Since a scram from high power level results in an unnecessary and undesirable transient cycle on the primary system, additional transient testing involving a scram from high power levels is not justifiable. Should any future large transients occur, HCGS 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. Transient mitigation capability is demonstrated by other tests required by the TS. In addition, the limiting transient analyses are included as part of the reload licensing analysis.

Specifically with respect to BOP systems, the objectives of the MSIV closure test do not test the functionality of the BOP systems nor does it require the function of these systems to satisfy the acceptance criteria as stated in the HCGS UFSAR. Therefore, this large transient test is not necessary to verify proper operation of BOP systems for EPU. For the TT/generator load rejection test, the objectives of the test do not require BOP systems, with the exception of the TBS. The acceptance criterion for this test requires the response time and capacity of the turbine bypass valves to be within design specifications. With constant steam pressure for the CPPU and no EPU modifications affecting the TBS, no new thermal-hydraulic phenomena are expected to affect the TBS. In addition, the limited scope of modifications and operating experience for similar units implementing a CPPU EPU supports the proper operation of the TBS.

The generator load rejection and TT events are considered potentially limiting events and are re-analyzed for each reload. The re-analysis of these events is performed with the failure of the main steam bypass system. These events, without the operability of this system, are more limiting so the generator load rejection and the TT event with main steam bypass system operable are not re-analyzed. With these two events re-analyzed for each reload and the TBS not required for these events, a generator load rejection and TT test for EPU testing of the TBS is not deemed necessary.

The HCGS TS have a limiting condition for operation (LCO) (3/4.7.7) for the TBS which requires it to be operable when thermal power is equal to or greater than 25 percent of rated thermal power. As part of the licensee's license amendment request for EPU, this LCO will be changed from 25 percent to 24 percent rated thermal power. The bases for the LCO is to meet the plant response criteria for the FW controller failure - maximum demand, described in Section 15.1.2 of the UFSAR which is considered a potentially limiting event and is re-analyzed for each reload. This event results in a high reactor vessel level trip of the main turbines and reactor FW pumps and corresponding reactor scram. Pursuant to TS 4.7.7 for surveillance testing, the response time and automatic actuation of the TBS is tested each refueling cycle to verify proper operation consistent with this analysis. Since this event is re-analyzed for each reload, a generator load rejection and TT large transient test is not necessary.

PSEG also conducted a review of risks associated with performing certain large transient tests as discussed in Attachment 6, Section 5.0, of their application. In this section, PSEG concluded that from a risk-informed perspective, the testing should be performed only if there are clear benefits that both outweigh the calculated risk and cannot be otherwise obtained through either simulator training or the occurrence of unplanned events.

Since the proposed EPU was not submitted as a risk-informed license amendment request, the staff did not perform a detailed review of the licensee's risk analysis. However, the staff recognizes that any transient, even those intentionally initiated under pre-staged 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 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 staff reviewed the applicant's justification for not performing certain original startup tests against the review criteria established in SRP 14.2.1. In justifying test eliminations or deviations, PSEG addressed several factors discussed in SRP 14.2.1 Section III.C.2. These factors included a discussion of previous industry operating experience at recently uprated BWRs, plant response to actual turbine and generator trip tests for other similar BWRs, and experience gained from actual plant transients. Additionally, PSEG followed the NRC staff-approved guidance contained in General Electric Company LTRs which the staff concluded meets the objectives of a suitable test program for CPPU, with exception of the recommendation to eliminate large transient testing.
The NRC staff evaluation of the licensee's justification for not performing large transient testing was found to be acceptable based on the following review criteria discussed in SRP 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 due to changes in thermal-hydraulic phenomena are limited;

- HCGS is in conformance with the limitations associated with applicable computer codes and analytical methods;

- HCGS plant staff familiarization with facility operation and use of operating and EOPs;
- Availability of adequate margin in safety analysis results for AOOs, and

- Compliance with NRC staff approved guidance contained in General Electric Company LTRs which the staff concluded meets the objectives of a suitable test program for CPPU, with exception of the recommendation to eliminate large transient testing.

The staff concludes that the licensee's power ascension and testing program provides reasonable assurance that plant SSCs that are affected by the proposed EPU will perform satisfactorily in service at the proposed power uprate level, and that the program complies with the quality assurance requirements of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control."

SRP 14.2.1 Section III.D
Evaluate the Adequacy of Proposed Transient Testing Plans

SRP 14.2.1 Section III.D, specifies the guidance and acceptance criteria the licensee should use to include plans for the initial approach to the increased EPU power level and testing that should be used to verify that the reactor plant operates within the values of EPU design parameters. The test plan should assure that the test objectives, test methods, and the acceptance criteria are acceptable and consistent with the design basis for the facility. The predicted testing responses and acceptance criteria should not be developed from values or plant conditions used for conservative evaluations of postulated accidents. During testing, safety-related SSCs relied upon during operation shall be verified to be operable in accordance with existing TS and quality assurance program requirements. The following should be identified in the EPU test program:

- the method in which initial approach to the uprated EPU power level is performed in an incremental manner including steady-state power hold points to evaluate plant performance above the original full-power level,

- appropriate testing and acceptance criteria to ensure that the plant responds within design predictions including development of predicted responses using real or expected values of items such as beginning-of-life core reactivity coefficients, flow rates, pressures, temperatures, response times of equipment, and the actual status of the plant,

- contingency plans if the predicted plant response is not obtained, and

- a test schedule and sequence to minimize the time untested SSCs important to safety are relied upon during operation above the original licensed full-power level.

The staff reviewed Attachment 23 of the application, "EPU Power Ascension Test Plan Overview," which described the HCGS PATP designed to assess selected piping system performance from 100 percent CLTP to 115 percent CLTP. The main elements of the PATP include power ascension, monitoring and analysis, and Post EPU monitoring. The staff also determined that the licensee adequately addressed EPU operating experience for similar designed plants (Hatch Units 1 and 2 and Brunswick) in determining the current proposed test plan.

The technical bases for the EPU request follows the guidelines contained in the following staff approved GE Nuclear Energy (GENE) LTRs for EPU safety analysis: NEDC-33004P-A, "Constant Pressure Power Uprate," (CLTR); NEDC-32424P-A, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," (ELTR1); and NEDC-32523P-A, "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate," (ELTR2). PUSAR Section 10.4, "Testing," submitted with the licensee's application, provides additional information relative to power uprate testing and describes a standard set of tests, which supplement the normal TS testing requirements, that have been established for the initial power ascension steps of CPPU. The test schedule would be performed in an incremental manner, with appropriate hold points for evaluation, and contingency plans would be utilized if predicted plant response is not obtained.

As previously stated, the staff found that all transient tests described in the initial startup test program, as derived from UFSAR Paragraph 14.2, were listed in Section 1.0 of PSEG Attachment 16. PSEG provided a table listing these tests which were initially performed during initial plant startup at greater than 80 percent OLTP, as detailed in Chapter 14 of the HCGS UFSAR. The tests included closure of all MSIVs at 99.6 percent power level (UFSAR Paragraph 12.3.21.3b) and a TT/generator load rejection test performed at 97 percent power (UFSAR Paragraph 12.3.23.3). These tests follow the tests described in Attachment 2 of SRP 14.2.1.

The staff has reviewed the licensee's EPU power ascension and test program including its conformance with applicable regulations and the staff guidance discussed in SRP 14.2.1. The staff concludes that the proposed EPU test plan will adequately assure that the test objectives, test methods, and test acceptance criteria are consistent with the design basis for the facility.

BOP Systems Testing Review

The NRC staff reviewed the licensee's power ascension and testing plan as it relates to those areas that are included within the scope of this evaluation and two areas are of interest in this regard. 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 (TG) load reject and TT transient analyses. Because the licensee is not proposing to credit additional steam bypass capacity beyond what was previously assumed and no modifications are being made to the steam bypass system for CPPU operation, transient testing for the purpose of demonstrating acceptable performance 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 that are necessary for implementing the proposed power uprate. Based on the results of previous power uprate evaluations, the NRC staff has found that transient testing considered necessary to demonstrate acceptable BOP performance is usually limited to the CFS. If the CFS modifications that are necessary for implementing the proposed power uprate are relatively extensive and recognizing that analytical uncertainties associated with BOP transient analyses are normally quite large, the NRC staff will typically require CFS pump trip testing from the full CPPU power level to confirm that the loss of a RFP, secondary condensate pump (SCP), or primary condensate pump (PCP) (taken individually) will not result in a total loss of FW event. The CFS modifications that are required for implementing the Hope Creek power uprate are not very extensive such that the licensee was able to perform transient analyses of CFS pump trip events at CPPU operating conditions that could be convincingly compared to the results of actual CFS pump trip events that have occurred at Hope Creek during CLTP operation, thereby adequately demonstrating acceptable CFS performance. Consequently, the NRC staff determined that CFS pump trip testing from the full CPPU power level is not necessary for the Hope Creek power uprate. Transient testing of the CFS is further discussed in Section 2.5.4.4 of the staff's SE.

Based on a review of the information that was provided, the NRC staff has determined that with the limited scope of EPU modifications for BOP systems, no introduction of new credible thermal-hydraulic phenomena, and past plant experience combined with a demonstration of acceptable plant performance during the power ascension test program, reasonable assurance exists that BOP systems will function as designed.

The NRC staff has reviewed the EPU test program, including plans for the initial approach to the proposed maximum licensed thermal power level, transient testing necessary to demonstrate that plant equipment will perform satisfactorily at the proposed increased maximum licensed thermal power level, and the test program's conformance with applicable regulations. The staff concludes that the proposed EPU test program provides reasonable assurance that the plant will operate in accordance with design criteria and that SSCs affected by the proposed EPU, or modified to support the proposed EPU, will perform satisfactorily in service. Further, the staff finds that there is reasonable assurance that the EPU testing program satisfies the requirements of 10 CFR Part 50, Appendix B, Criterion XI and the review criteria in SRP 14.2.1. Therefore, the NRC staff finds the proposed EPU test program acceptable.

Conclusion

The staff has reviewed the licensee's EPU power ascension and testing program, including plans for the initial approach to the proposed maximum licensed thermal power level, transient testing necessary to demonstrate that plant equipment will perform satisfactorily at the proposed increased maximum licensed thermal power level, and the test program's conformance with applicable regulations. The review included an evaluation of 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. PSEG's test program primarily includes steady state testing with no large transient testing proposed.
The staff also reviewed the licensee's justification for not performing large transient testing as discussed in Attachment 16 to the application. The staff evaluation of the licensee's justification was found to be acceptable based on the applicable review criteria discussed in Section III.C.2 of SRP 14.2.1.

Based on the staff's review of the licensee's power ascension and test program, the 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 power increase, will perform satisfactorily in service. Further, the staff finds that there is reasonable assurance that the EPU testing program satisfies the requirements of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," and the staff guidance and review criteria in SRP 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

Regulatory Evaluation

A risk evaluation is conducted to: (1) demonstrate that the risks associated with the proposed EPU are acceptable; and (2) determine if "special circumstances" are created by the proposed EPU. As described in Appendix D of SRP Section 19.2, special circumstances are any issues that would potentially rebut the presumption of adequate protection provided by the licensee to meet the deterministic requirements and regulations. The NRC staff's review covers the impact of the proposed EPU on core damage frequency (CDF) and large early release frequency (LERF) for the plant due to changes in the risks associated with internal events, external events, and shutdown operations. In addition, the NRC staff's review covers the quality of the risk analyses used by the licensee to support the application for the proposed EPU. This includes a review of licensee actions to address issues or weaknesses that my have been raised in previous NRC staff reviews of the licensee's individual plant examinations (IPEs) and individual plant examinations of external events (IPEEE), or by an industry peer review. The NRC's risk acceptability guidelines are contained in RG 1.174. Specific review guidance is contained in Matrix 13 of RS-001 and its attachments.

Technical Evaluation

The NRC staff has reviewed the risk evaluation submitted by the licensee,[269] as supplemented by responses to the staff's RAIs. In general, the licensee's risk evaluation compared the risks of the pre-EPU to the post-EPU plant design and operation. A combination of quantitative and qualitative methods was used to assess the risk impacts of the proposed EPU.

The following sections discuss the staff's technical evaluation of the risk information provided by the licensee. Specifically, Section 2.13.2.1 summarizes the changes in plant design and operations that will occur upon EPU implementation that affect the risk evaluation. The impact of the proposed EPU on the full-power core-damage (Level 1) risk is discussed in Section 2.13.2.2; similarly, the impact of the proposed EPU on the full-power large, early release (Level 2) risk is discussed in Section 2.13.2.3. An evaluation of the proposed EPU on shutdown risks is presented in Section 2.13.2.4. Finally, the quality of the probabilistic risk assessment (PRA) used to support the risk evaluation is discussed in Section 2.13.2.5.

2.13.2 Full Power Level 1 Risk

2.13.2.1 Changes in Plant Design and Operations

The proposed EPU increases the licensed thermal power level to 3840 MWt, approximately 15 percent above the CLTP of 3339 MWt and 16.6 percent above the OLTP of 3293 MWt. The method for achieving higher power is to extend the power/flow map along the MELLLA. The proposed EPU is a CPPU that increases the CLTP without changing the reactor operating pressure and temperature, which results in the generation and supply of higher steam flow to the TG.

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[269] Hope Creek Generating Station Updated Final Safety Analysis Report, Revision 14, dated July 26, 2005,ADAMS Accession No. ML052220616

The licensee identified the following plant modifications associated with the proposed EPU that affect the risk estimate:

1. Turbine First Stage Pressure (TFSP) Scram Bypass Permissive setpoint will be changed from 30 percent CLTP to 24 percent CLTP. As a result, many inputs to scram will be "armed" at a lower power level than before CPPU, thereby reducing the margin between the nominal operating band and the scram setpoint.

2. The condenser backpressure operating value will be increased from 4.0 inches of mercury absolute (inches HgA) to between 4.5 and 4.8 inches HgA, nominally during summer months. This modification reduces the operating margin between the operating condenser vacuum and: (1) the TT (7.5 inches HgA); (2) the trip of all FW (10.0 inches HgA); and (3) the MSIV closure setpoint (21.5 inches HgA).

3. The parameter thresholds and graphs contained in the EOPs and severe accident management guidelines (SAMGs) will be revised to reflect EPU conditions. It should be noted that the EOP and SAMG structure will remain unchanged from their current symptom-based philosophy. The EOP variables that play a role in the PRA and may require adjustment for the proposed EPU include:

    a. Boron Injection Initiation Temperature (BIIT)

    b. Heat Capacity Temperature Limit (HCTL)

    c. Primary Containment Pressure Limit (PCPL)

In addition, the licensee determined that the following plant modifications which have been or will be made to implement the proposed EPU do not impact the PRA:

1. Operating range flexibility analysis (MELLLA)

2. Addition of a 500 kV breaker in the Hope Creek substation

Replacement of the A and B phase generator step up (GSU) transformers

1. Main generator stator water cooling pump upgrades

2. Replacement of the HP and LP turbines

3. Cooling tower improvements

4. Feedwater heater dump valve replacement

5. Moisture separator upgrades

6. Replacement of analog EHC with digital EHC

7. Modifications to the isolated phase bus to increase rating

2.13.2.2 Full-Power Level 1 Risk Evaluation

The following sections discuss the impact of the proposed EPU on the full-power core-damage (Level 1) risk. The discussion has been organized into two main parts: Section 2.13.2.2.1 addresses the Level 1 risks arising from the occurrence on internal initiating events, and Section 2.13.2.2.2 provides similar discussion concerning external events.

2.13.2.2.1 Full-Power Level 1 Internal Events Risk Evaluation

The licensee maintains a Level 1 PRA for the HCGS that estimates the CDF due to internal initiating events (including internal floods). The risk impacts of the proposed EPU due to internal initiating events were assessed by reviewing the changes in plant design and operations resulting from the proposed EPU, mapping these changes onto appropriate PRA elements, modifying affected PRA elements as needed to capture the risk impacts of the proposed EPU, and requantifying the PRA to determine the post-EPU CDF.

The following sections discuss the impact of the proposed EPU on the internal events PRA initiating event frequencies (Section 2.13.2.2.1.1), component failure rates (Section 2.13.2.2.1.2), accident sequences and success criteria (Section 2.13.2.2.1.3), operator actions and recovery from LOOP events (Section 2.13.2.2.1.4). The combined impact of the proposed EPU on the full-power Level 1 PRA results is presented in Section 2.13.2.2.1.5.

2.13.2.2.1.1 Initiating Event Frequencies

The HCGS PRA addresses 35 internal initiating events, including 17 transients, 11 internal flooding initiators, and 7 LOCAs. The set of internal initiating events used in the pre-EPU PRA was used in the post-EPU PRA without modification.

The licensee stated that generic data was combined with HCGS operating experience using Bayesian methods to determine the frequencies of the transient initiators. The transient initiator frequencies should not increase as a result of EPU operations because:

- The proposed EPU does not result in plant equipment operation beyond design ratings and conditions,

- The results of a licensee-conducted review of the 11 BWRs now operating at EPU conditions, which included about 12 reactor-years of experience, did not indicate any trend towards increased transient initiator frequencies due to EPU implementation, and

- The results of a licensee-performed engineering assessment of the transient initiators with the most potential to be affected by the proposed EPU due to changes in reactor or TT setpoints (e.g., reactor scram, system isolations, and operating equipment trips) concluded that adequate operating margins will be maintained and, therefore, changes to the pre-EPU transient initiator frequencies to reflect post-EPU operations were not needed.

Nevertheless, the licensee decided to increase the frequency of the TT initiator by 21 percent to account for the potential impacts of the proposed EPU. The 21 percent increase was based on engineering judgment as follows:

1. The TCV fast closure and TSV closure will be enabled at a lower power level in the post-EPU plant as compared to the pre-EPU plant, which may result in additional plant trips. This effect is modeled as a 10 percent increase in the TT frequency

2. The reduction in margin between the condenser backpressure setpoint and the nominal operating conditions as a result of the proposed EPU may result in additional plant trips. This effect is modeled as a 10 percent increase in the TT frequency.

3. Changes to the reactor recirculation runback logic to allow EPU implementation may result in additional plant trips. This effect was modeled as a 1 percent increase in the TT frequency.

The licensee's PRA model includes an event that represents the LOOP following a trip of the plant. Such an event may happen because the rapid separation of a large generating unit from the grid has the potential to cause grid instability and a subsequent LOOP. The licensee performed a deterministic grid stability analysis, considering the increase in electrical output that will result from the proposed EPU, that demonstrates conformance to GDC 17. In addition, an analysis of the PJM Interconnection was performed for the worst-case three-phase or single-phase fault, which identified the need to add another 500kV breaker to the plant switchyard to ensure post-trip grid stability. The implementation of this plant modification makes the pre-EPU and post-EPU grid response the same; therefore, the licensee concluded that no change to the conditional LOOP probability was necessary. The contribution of a post-trip LOOP events to the post-EPU internal events CDF is shown below:

Contribution of Post-Trip LOOP Events to Core-Damage Frequency		
Scenario	Conditional LOOP Probability	Percent Contribution to the Post-EPU Internal Events CDF
Plant trip without subsequent LOCA signal	3×10^{-3}	8.3%
Plant trip with subsequent LOCA signal	1×10^{-2}	< 0.2%

The staff compared the licensee's estimates of conditional LOOP probabilities to data and information presented in Volume 1 of NUREG/CR-6890, "Reevaluation of Station Blackout Risk at Nuclear Power Plants, Analysis of Loss of Offsite Power Events: 1986-2004." In this report, the distinction between the absence or presence of a post-trip LOCA signal is not considered. The average conditional LOOP probability was estimated as 5.3×10^{-3} for the period 1997-2004. For the five summer months (May - September), the conditional LOOP probability was estimated as 9.1×10^{-3}. The staff observes that estimates of conditional LOOP probabilities are based on sparse data and, hence, contain uncertainty. Therefore, there does not appear to be a significant difference between the licensee's and the staff's estimates of conditional LOOP probabilities.

The licensee considered the impact of the proposed EPU on the LOCA frequencies used in the PRA due to the potential for Flow-Induced Vibration (FIV) and FAC by conducting sensitivity analyses. Details of the licensee's analysis and its results are presented below:

Licensee PRA Sensitivity Analyses Related to Flow Induced Vibration and Flow Accelerated Corrosion			
Concern	**Approach**	**Change in Post-EPU Internal Events CDF (per year)**	**Percent Change in Post-EPU Internal Events CDF**
FAC may increase main steam or feedwater pipe failure probability	Double the large LOCA frequency	2.3×10^{-7}	2.3%
FIV could result in an increased plant trip frequency due to effects on the reactor internals or small-bore attached piping.	Double the turbine trip frequency	1.6×10^{-6}	15.8%
FIV may cause an inadvertent open safety relief valve (IORV)	Double the IORV frequency	1.7×10^{-7}	1.7%

The licensee's sensitivity analyses indicate that the post-EPU internal events CDF is somewhat sensitive to the TT frequency, which may be increased as a result of the proposed EPU due to the potential impact of FIV on the reactor internals and small-bore attached piping. The staff observes that

- The EPU-related testing will be conducted in steps to detect FIV and, if necessary, shutdown the plant before significant fatigue damage occurs,

- The conditional core-damage probability (CCDP) following a TT is on the order of 1×10^{-6}.

Therefore, the staff concludes that there is a very small likelihood that FIV will lead to a plant trip, or that a FIV-related plant trip will lead to core damage.

No significant changes to support systems (e.g., instrument air, service water) are planned in support of the proposed EPU. As such, no effect on support system initiating event frequencies due to the proposed EPU were postulated.

No changes to pipe inspection scopes or frequencies are planned in support of the proposed EPU. As such, no effect on internal flooding initiator frequencies due to the proposed EPU were postulated.

The frequency of external event initiators (e.g., seismic events, extreme winds, fires) is not linked to reactor power or operation. As such, no effect on external event initiator frequencies due to the proposed EPU were postulated.

The NRC staff finds acceptable the licensee's assessment of the impact of the proposed EPU on initiating event frequencies, because the assessment has:

- Considered the plant-specific impacts of the proposed EPU;
- Adequately mapped the plant-specific impacts of the proposed EPU onto the appropriate PRA internal initiating events, and
- Integrated information from engineering analyses, operational experience, and the plant-specific performance history.

2.13.2.2.1.2 Component Failure Rates

The licensee stated that under EPU conditions, equipment operating limits, conditions, and ratings will not be exceeded. As a result, the component failure rates used in the post- EPU PRA model are the same as those used in the pre-EPU PRA mode, with one exception.

The licensee evaluated the impact of the proposed EPU on the probability of a stuck-open relief valve (SORV). The SRV setpoints will not be changed as a result of proposed EPU. Given the power increase of the proposed EPU, it may be postulated that the probability of an SORV given a transient initiator would increase due to an increase in the number of SRV cycles. The licensee modified the SORV probability by assuming that it is linearly proportional to the number of SRV cycles, and determining the expected number of SRV cycles during accident response through thermal-hydraulic analyses performed using the modular accident analysis program (MAAP) code. It was determined that for accident sequences that do not involve an ATWS, the number of expected SRV cycles increased by about 13 percent for the post-EPU plant. For ATWS-related sequences, it was determined that the number of expected SRV cycles increased by about 9 percent for the post-EPU plant. Results of the licensee's analysis are provided below:

Comparison of SORV Probabilities		
Accident Scenario	Pre-EPU SORV Probability	Post-EPU SORV Probability
Turbine Trip	1.5×10^{-2}	1.8×10^{-2}
Isolation Event or Small Loss-of-Coolant Accident (SLOCA)	4.8×10^{-2}	5.4×10^{-2}
ATWS	5.3×10^{-2}	5.4×10^{-2}

The NRC staff finds acceptable the licensee's assessment of the impact of the proposed EPU on component failure rates, because the assessment has:

- Considered the plant-specific impacts of the proposed EPU;
- Adequately mapped the plant-specific impacts of the proposed EPU onto the appropriate PRA basic events, and

- Integrated information from engineering analyses, operational experience, and the plant-specific performance history.

2.13.2.2.1.3 Accident Sequence Delineation

The licensee conducted thermal-hydraulic analysis using MAAP 4.0.4 to determine how the proposed EPU affected the PRA success criteria. As indicated in the following table, the proposed EPU impacts the success criteria related to RPV pressure control:

Impact of Proposed EPU on PRA Success Criteria			
Function	Pre-EPU	Post-EPU	Notes
Reactivity control	Reactor protection system (RPS) or Standby liquid control (SLC)	no change	At HCGS, SLC is automatically initiated.
RPV overpressure protection during anticipated transients without scram (ATWS)	Recirculation pump trip (RPT) and 11 of 14 SRVs open	RPT and 12 of 14 SRVs open	
RPV overpressure protection during non-ATWS events	4 of 14 SRVs open	no change	
RPV depressurization to allow use of low-pressure injection	1 SRV open	2 SRVs open	
High-pressure RPV inventory makeup (sequence-specific)	FW or high-pressure coolant injection (HPCI) or reactor core isolation cooling (RCIC)	no change	Control rod drive (CRD) injection is only adequate in the long-term.
Low-Pressure RPV inventory makeup (sequence-specific)	condensate or low-pressure coolant injection (LPCI) or core spray (CS)	no change	

Based on the results of the thermal-hydraulic analyses, no changes were required to the event tree structure.

The NRC staff finds acceptable the licensee's assessment of the impact of the proposed EPU on the PRA accident sequence delineation because the assessment has:

- Considered the plant-specific impacts of the proposed EPU;

- Adequately mapped the plant-specific impacts of the proposed EPU onto the appropriate PRA logic model elements, and

- Integrated information from engineering analyses, operational experience, and the plant-specific performance history.

2.13.2.2.1.4 Operator Actions and LOOP Recovery

The human reliability analysis (HRA) focused on evaluating the impact of the proposed EPU on the post-trip operator actions. No new human actions were identified by the licensee as a result of the proposed EPU. The HCGS 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. The performance shaping factor that is principally influenced by the proposed EPU is the time available to detect, diagnose, and perform required actions. The higher power level results in reduced times available for some actions. To quantify the potential effect of this performance-shaping factor, deterministic thermal-hydraulic calculations using the MAAP 4.0.4 computer code were used. Specifically, the licensee assumed a post-EPU power level of 3952 MWt, which is an approximately 20 percent increase over the OLTP of 3293 MWt and an approximately 18 percent increase over the CLTP level of 3339 MWt. This approach is conservative since the actual proposed EPU would raise the power level to 3840 MWt, an approximately 15 percent increase over the CLTP level.

The human error probability (HEP) of a post-trip human action consists of two main parts: (1) the probability of cognitive error (errors in diagnosis and decision making); and (2) the probability of implementation error (execution errors). Cognitive errors were generally estimated using the Caused-Based Decision Tree Method (CBDTM) developed by EPRI in EPRI TR-100259, "An Approach to the Analysis of Operator Actions in PRA." For post-trip actions with short (less than 1 hour) time available for diagnosis, a time-dependent contribution determined using the Accident Sequence Evaluation Program (ASEP) methodology described in NUREG/CR-4772, "Accident Sequence Evaluation Program Human Reliability Analysis Procedure," was added to the CBDTM result. The probability of an implementation error was estimated using the Technique for Human Error Rate Prediction (THERP) described in NUREG/CR-1278, "Handbook of Human Reliability Analysis with Emphasis on Nuclear Power Plant Applications." All calculations were performed using the HRA Calculator developed by EPRI.

The following table lists the significant post-initiator human actions, and includes the following information about them:

- PRA model basic event name and description,
- Pre-EPU available time and HEP,
- Post-EPU available time, HEP, Fussell-Vesely (FV) importance measure, and risk achievement worth (RAW), and
- Notes related to how the EPU impact was considered.

Significant Post-Initiator Human Actions								
Basic Event	Description	Pre-EPU		Post-EPU				Notes
		Available Time	HEP	Available Time	HEP	FV	RAW	
NR-XTIE-EDG	Failure to cross-tie diesel generator to opposite bus	4 h	1.0	4 h	1.0	0.399	1.0	Placeholder in the PRA model; action is not proceduralized.
ACP-XHE-RE-SW04H	Failure to recover severe weather LOOP (4 hours)	4 h	0.472	4 h	0.472	0.228	1.25	Available time based on battery discharge time, which is not affected by the proposed EPU LOOP non-recovery probability estimated from NUREG/CR-5496
NR-XTIE-CHARG	Failure to crosstie energized bus to battery changer breaker	3 h	0.6	3 h	0.6	0.177	1.12	Available time based on battery discharge time, which is not affected by the proposed EPU
ACP-XHE-RE-PC04H	Failure to recover plant centered and grid related LOOP (4 hours)	4 h	0.154	4 h	0.154	0.154	2.40	Available time based on battery discharge time, which is not affected by the proposed EPU LOOP non-recovery probability estimated from NUREG/CR-5496
SAC-XHE-FO-HEA5B	Dependent combination of SAC-XHE-FO-HEAT, failure of SACS heat load manipulation, and SWS-XHE-FO-2355B, failure to open SACS-SW heat exchanger valve 2355B locally	46 m	9.04×10^{-3}	40 m	1.04×10^{-2}	0.116	6.36	Evaluated at the worst-case conditions of high river water temperature and high SACS temperatures.

Significant Post-Initiator Human Actions								
Basic Event	Description	Pre-EPU		Post-EPU				Notes
		Available Time	HEP	Available Time	HEP	FV	RAW	
NR-VENT-5-03	Failure to initiate containment venting	20 h	2.59×10^{-3}	20 h	2.59×10^{-3}	0.115	45.5	Long-term action whose available time is not greatly affected by EPU conditions
ADS-XHE-OK-INHIB	Automatic ADS inhibited (non-ATWS) - success of the action	14 m	1.0	12 m	1.0	0.075	1.0	This event represents a successful human action; decreasing the success probability decreases the CDF
ACP-XHE-RE-SW20H	Failure to recover severe weather LOOP (20 hours)	20 h	0.162	20 h	0.162	0.066	1.34	LOOP non-recovery probability estimated from NUREG/CR-5496
CAC-XHE-FO-NPSH	Failure to prevent steam binding of ECCS pump during containment venting	80 m	0.21	69 m	0.21	0.064	1.24	No change in HEP using the CBDTM
NR-SPL-LVLL-4	Failure to align core spray to the CST for late injection (post containment challenge)	> 24 h	0.204	> 24 h	0.204	0.064	1.25	Available time based on time to reach the ultimate containment failure pressure
SAC-XHE-FO-HEA5A	Dependent combination of SAC-XHE-FO-HEAT, failure of SACS heat load manipulation, and SWS-XHE-FO-2355A, failure to open SACS-SW heat exchanger valve 2355A locally	46 m	9.04×10^{-3}	40 m	1.04×10^{-2}	0.056	1.0	Valve 2355A is normally open Joint HEP dependency modeled using THERP

Significant Post-Initiator Human Actions								
Basic Event	Description	Pre-EPU		Post-EPU				Notes
		Available Time	HEP	Available Time	HEP	FV	RAW	
UV1-XHE-FO-ALIGN	Failure to align FP for late RPV injection	20 h	0.99	20 h	0.99	0.053	1.0	Procedural limitations - allowed by the Severe Accident Management Guidelines (SAGS), but not addressed in the Emergency Operating Procedures (EOPs)
SWS-XHE-PROC	Failure to align SSW for late RPV injection	20 h	1.0	20 h	1.0	0.053	1.0	Procedural limitations - allowed by the SAGS, but not addressed in the EOPs
NR-U1X-DEP-SRV	Failure to depressurize with SRV without high pressure injection	33 m	2.6×10^{-4}	27 m	3.6×10^{-4}	0.047	131	Available time determined by MAAP calculations
NR-%IE-SWS	Non-recovery of %IE-SWS	N/A	0.1	N/A	0.1	0.035	1.32	Loss of SWS initiating event

Significant Post-Initiator Human Actions								
Basic Event	Description	Pre-EPU		Post-EPU				Notes
		Available Time	HEP	Available Time	HEP	FV	RAW	
RX-FW-ADS	Dependent operator actions - operator fails FW control (NRQFWLVH4M-03) and ADS (NR-U1X-DEP-SRV)	4 to 30 m	1.8×10^{-5}	4 to 27 m	2.4×10^{-5}	0.02	832	Joint HEP dependency modeled using THERP NRQFWLVH4M-03 represents failure to reduce feedwater flow before potentially reaching the Level 8 high level trip following a plant trip, and has an estimated available time of 4 minutes that is not sensitive to EPU NR-U1X-DEP-SRV represents failure to depressurize with the SRVs without high pressure injection, and has an estimated time of 30 minutes for pre-EPU conditions, and 27 minutes for post-EPU conditions
SAC-XHE-FO-HEAT	SACS heat load manipulation	46 m	9.04×10^{-3}	40 m	1.04×10^{-2}	0.019	6.36	Evaluated at the worst-case conditions of high river water temperature and high SACS temperatures
RHS-REPAIR-TR	Repair/recovery of RHR for loss of DHR events	20 h	0.35	20 h	0.35	0.019	1.04	RHR pump mean time to repair of 19 hours
IGS-XHE-FO-V5125	Failure to open cross-connect valve	20 h	0.118	20 h	0.118	0.011	1.09	This action supports containment venting

Significant Post-Initiator Human Actions								
Basic Event	Description	Pre-EPU		Post-EPU				Notes
		Available Time	HEP	Available Time	HEP	FV	RAW	
NR-RHR-INIT-L	Failure to initiate RHR (late)	20 h	2.1×10^{-6}	20 h	2.1×10^{-6}	0.010	4710	Available time based on the time to pressurize the containment and close the SRVs

In order to review the licensee's HRA, the staff considered the guidance and insights provided in NUREG-1842, "Analysis of Human Reliability Analysis Methods Against Good Practices," which was issued in September 2006 (i.e., shortly before the licensee submitted its EPU application). Since the EPU was not a risk-informed application, the staff did not have the benefit of detailed information that would allow review of the licensee's approach to the identification or modeling of the human actions in the PRA, or the context surrounding each of the modeled human actions. The staff agrees with the licensee's conclusion that no new human actions need be incorporated into the PRA to represent the proposed EPU based on a review of equipment changes needed to implement the proposed EPU; the staff observes that the licensee's conclusion is consistent with other licensees who have conducted risk assessments of EPUs. Knowledge of the context surrounding each of the modeled human actions (e.g., what sequences are addressed, what additional equipment failures have occurred) is important to ensure that the correct HEPs have been assigned. The staff agrees with the licensee's conclusion that the main impact of the proposed EPU on the post-initiator human actions is the reduction in time available for the plant operators to detect, diagnose, and perform required actions. Therefore, any inadequacies or errors in: (1) the identification and modeling of human actions; or (2) consideration of the context surrounding each human action that may affect the assignment of performance shaping factors (other than available time) used to estimate the HEPs appear in both the pre-EPU and the post-EPU models and, thus, tend to cancel out (i.e., they should not noticeably affect the estimation of the change in risk due to the proposed EPU, even though they may impact the estimation of the total risk at pre-EPU or post-EPU conditions).

The licensee's use of thermal-hydraulic analyses, knowledge of equipment capacities (e.g., battery depletion time), and interviews with plant operators to determine the change in the time available for diagnosis and decision-making for the post-initiator operator actions is consistent with good PRA practices. The staff observes that the apparent small changes in the available times, and the corresponding changes in the post-initiator HEP values, should not be taken literally since the parameters and models used to obtain them are uncertain. However, the staff believes that the licensee's analysis is adequate to conclude that the change in post-initiator HEP values due to the proposed EPU is small.

The licensee's use of two HRA quantification methods (CBDTM and ASEP) for time-limited post-initiator human actions is consistent with NUREG-1842. Specifically, NUREG-1842 states that the time reliability correlation (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 staff observes that many HRA practitioners simply pick an HRA quantification method in advance of conducting the PRA, and apply it to all post-initiator events regardless of their associated available times for diagnosis and decision-making. From this perspective, the licensee's approach to estimating the HEPs of time-limited post-initiator operator actions appears conservative.

The staff noted that one of the post-initiator human actions involved the repair of the RHR system while accident sequences were progressing (event RHR-REPAIR-TR). Equipment repair is not typically included in PRA because of the difficulty in obtaining credible data (e.g., through statistical methods or expert elicitation) that can be used to estimate the probability of non-repair under accident conditions. However, this non-conservatism in the PRA model does not appear to be significant since the RAW of the event is approximately 1.04.

The HCGS PRA model credits recovery of offsite power for SBO sequences. The licensee used NUREG/CR-5496 to obtain off-site power (OSP) non-recovery probabilities, and indicated that none of the OSP non-recovery probabilities were adjusted to model the post-EPU plant. The staff observes that this source of data is somewhat dated. To confirm the OSP non-recovery probabilities used by the licensee, the staff compared them to LOOP duration data recently collected and analyzed by the NRC in response to the August 2003 Northeast Blackout (Volume 1 of NUREG/CR-6890, "Reevaluation of Station Blackout Risk at Nuclear Power Plants, Analysis of Loss of Offsite Power Events: 1986-2004"). The staff also observes that the proposed EPU has no obvious cause-and-effect relationship to OSP non-recovery probabilities. The staff concludes that the licensee's assessment of OSP non-recovery probabilities is reasonable because it produces values that are similar to those recently determined by the NRC staff.

2.13.2.2.1.5 Full-Power Level 1 Internal Events Results

The licensee stated that the proposed EPU increases the CDF by 6.8×10^{-7}/year (an increase of approximately 7 percent from the pre-EPU CDF of 9.42×10^{-6}/year to the post-EPU CDF of 1×10^{-5}/year). A Monte Carlo analysis of the parametric uncertainties determined that the fifth percentile of the post-EPU CDF is about 5×10^{-6}/year, and that the ninety-fifth percentile is about 2×10^{-5}/year. The licensee observed that the change in the full-power internal event CDF due to the proposed EPU lies inside this estimated uncertainty range.

The increase is due to the change in the TT frequency, SRV-related success criteria, and the reduced times for certain operator actions. The following table shows the contributions to the total change in CDF due to specific EPU-related impacts:

EPU-Related Impacts on Core-Damage Frequency	
Specific EPU-Related Impact	Change in CDF (per year)
Reduction in available margin: • Turbine first stage pressure (TFSP) scram bypass permissive • Time available for operator action given FW controller failure • Condenser backpressure setpoint • Spurious recirculation runback or failure to actuate	2.5×10^{-7}
Reduced time available for operator actions	3.1×10^{-7}
Increase in SORV failure probability	1.4×10^{-8}
Modification of depressurization success criteria	5.0×10^{-9}
Success criteria for ATWS overpressure protection	below PRA truncation value of 5×10^{-11}

The NRC staff finds that the licensee's evaluation of the impact of the proposed EPU on internal initiating event risk is reasonable because it is based on methodologies previously accepted by the staff for use in IPEs and EPU risk evaluations. Since the CDF risk metrics satisfy the risk acceptance guidelines in RG 1.174, the staff concludes that the change in internal initiating event risk due to the proposed EPU is very small and that there are no issues concerning internal initiating events that rebut the presumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements.

2.13.2.2.2 Full-Power Level 1 External Events Risk Evaluation

The following sections discuss the impact of the proposed EPU on full-power Level 1 external event risks. Specifically, the impact on fire risk is discussed in Section 2.13.2.2.2.1, the impact on seismic risk is discussed in Section 2.13.2.2.2.2 , and the impact on other external events (e.g., high winds) is discussed in Section 2.13.2.2.2.3.

2.13.2.2.2.1 Full-Power Level 1 Fire Risk Evaluation

The HCGS plant risk due to internal fires was evaluated in 1997 as part of the IPEEE using the fire induced vulnerability evaluation (FIVE) methodology developed by EPRI. The intent of the IPEEE program was to identify plant vulnerabilities pertaining to severe accidents, and the NRC staff has accepted the FIVE methodology as acceptable for that purpose. The HCGS IPEEE internal fire analysis identified the most risk significant fire areas in the plant using a screening process and by calculating conservative core damage frequencies for fire scenarios. The IPEEE reported that the total CDF due to internal fires was estimated as 8.1 x 10^{-5}/year. The licensee stated that the fire CDF should be viewed as an upper bound because of the extremely conservative assumptions in the fire damage modeling. The following table indicates the significant contributions to fire risk as identified in the IPEEE:

Significant Contributions to Fire Risk as Identified in the Individual Plant Examination of External Events					
Building - Elevation	Affected Room(s)	Description	Fire-Induced Initiating Events	Fire CDF (per year)	Percent of Total Fire CDF
Auxiliary Building - 137'	5510, 5511	Control Room	MSIV closure LOOP SORV Loss of HVAC Loss of SWS Loss of SACS	2.5 x 10^{-5}	30.86
Auxiliary Building - 130'	5416, 5417	Class 1E (Channel A) Switchgear Room	MSIV Closure	1.3 x 10-5	16.05
Auxiliary Building - 102'	5307	Diesel Generator (Channel A)	LOOP MSIV Closure	5.3 x 10-6	6.54
RB - 77'	4202	CRD Pump Area	MSIV Closure	4.2 x 10-6	5.19
Auxiliary Building - 102'	5306	Diesel Generator (Channel B)	LOOP MSIV Closure	4.1 x 10-6	5.06

Significant Contributions to Fire Risk as Identified in the Individual Plant Examination of External Events					
Building - Elevation	Affected Room(s)	Description	Fire-Induced Initiating Events	Fire CDF (per year)	Percent of Total Fire CDF
Auxiliary Building - 102'	5305	Diesel Generator (Channel C)	LOOP MSIV Closure	3.7 x 10-6	4.57
Auxiliary Building - 103'	5412, 5413	Class 1E (Channel B) Switchgear Room	MSIV Closure	3.0 x 10-6	3.70
Auxiliary Building - 137'	5501	Electrical Access	MSIV Closure	3.0 x 10-6	3.70
Auxiliary Building - 102'	5336	Electrical Access	MSIV Closure	2.7 x 10-6	3.33
Auxiliary Building - 163.6'	5605, 5631	Upper Control Equipment Computer Rooms	MSIV Closure	2.7×10^{-6}	3.33
Auxiliary Building - 102'	5304	Diesel Generator (Channel D)	LOOP MSIV Closure	2.6×10^{-6}	3.21
Auxiliary Building - 124'	5401, 3425	Electrical Access	MSIV Closure	2.0×10^{-6}	2.47
Reactor Building - 102'	4301, 4309 4310, 4311	North Side and Division 1 SACS Area	MSIV Closure	1.8×10^{-6}	2.22
Auxiliary Building - 102'	5302	Lower Control Electrical Equipment Room	LOOP SORV MSIV Closure	1.7×10^{-6}	2.10
Turbine Building - 102'	1315, 1316 1317, 1320 1321, 1322	Access and Unloading Area	LOOP	1.2 x 10-6	1.48
Reactor Building - 102'	4303	Motor Control Center (MCC) Area	MSIV Closure	1.2 x 10-6	1.48

The licensee stated that the fire risk evaluation performed for the IPEEE had not been updated for the post-EPU plant. The staff observes that the fire risk evaluation uses four types of information and data:

1. Fire ignition frequencies;

2. For each fire scenario, the set of equipment directly damaged by the fire;

3. Fire detection and suppression probabilities; and

4. For each fire scenario, the CCDP, which is developed from the internal events PRA model to address the random failure of equipment during the fire scenario.

The staff believes that it is reasonable to assume that the proposed EPU does not change the fire ignition frequencies, the set of equipment damaged in each fire scenario, and the fire detection and suppression probabilities because there have been no significant changes to either room-specific combustible loadings, plant and equipment layout, or the fire protection systems as a result of the proposed EPU. However, the fire-scenario-specific CCDP values used in the IPEEE do not reflect any changes made to the internal events PRA models since completion of the IPEEE or any EPU-specific impacts.

In response to a staff question, the licensee identified the significant changes made to the internal events PRA model since completion of the IPEEE fire risk evaluation. The licensee indicated that substantial changes had been made (e.g., update of the event tree accident sequence modeling, incorporation of realistic success criteria based on thermal-hydraulic analyses, revision of the HRA, revision of the fault tree analyses to reflect plant modification, and update of component failure rates and common-cause failure parameters). Qualitatively, it appears that these internal events PRA model changes and parameter updates would result in less impact from fires than estimated for the IPEEE since the internal events CDF has been reduced by about a factor of five, from the original IPE value of 4.6×10^{-5}/year to the current value of 9.42×10^{-6}/year (pre-EPU), while the EPU-related changes have only increased the internal events CDF by about 7 percent to 1.01×10^{-6}/year (post-EPU).

In response to a staff question, the licensee described the impact of the EPU on the top five fire sequences, which represent approximately 64 percent of the IPEEE fire CDF. The impact from the contributors of the remaining 36 percent of fire CDF are expected to be similar to the impacts depicted by the top five fire sequences. The changes in the top five fire contributors as a result of the change in power level from the pre-EPU to the EPU configuration are described below.

Control Room

This fire scenario contributes about 31 percent to the base IPEEE fire CDF. Control room fire scenarios are dominated by large, unsuppressed fires that involve abandonment of the control room and rely on operations from the remote shutdown panel. The CCDP for this scenario is dominated by operator failure to control the plant from the remote shutdown panel, which remains the same regardless of the EPU or pre-EPU power level since it is dominated by access and stress-related performance shaping factors (i.e., timing differences would not be a significant factor). No other changes to the HCGS internal events PRA model since the IPEEE were judged to have an impact on this sequence.

Class 1E (Channel A) Switchgear Room

Fires in this room contributes about 16 percent to the base IPEEE fire CDF. The fire analysis assumed that any cabinet fire in this room would cause a loss of the channel, which would result in a loss of electrical power to Channel A safety-related equipment. The CCDP is dominated by random failures of the Channel B equipment. The licensee stated that no change in CCDP is expected as a result of implementation of the EPU.

Diesel Generator (Channel A) Room

Fires in this room contributes about 7 percent to the base IPEEE fire CDF. The contribution from fires in the diesel generator rooms is primarily because both sets of Class 1E 4kV offsite power bus bars run along the ceiling of these rooms. In the fire analysis, a loss of offsite 4kV power was assumed for fires large enough to cause a short circuit of the bus bars. Because the bus bars run in relatively close proximity to each other at the diesel exhaust manifold end of the room, the loss of both bus bars was assumed to occur simultaneously. A large fire was also assumed to disable the EDG that initiated the fire and the CCDP is dominated by common cause failure (CCF) of the remaining EDGs.

For fires in the EDG A room, HPCI and/or RCIC are initially available for most sequences, resulting in core damage being delayed by several hours. Therefore, the impact of EPU on operator action timing is limited and the change in CDF or CCDP is expected to be negligible as a result of implementation of the EPU. Further, the licensee indicated that the CDF for this sequence would be reduced based on industry trends and studies that show decreases in both the EDG random failure and CCF probabilities. No other changes to the HCGS internal events PRA model since the IPEEE were judged to have an impact on this sequence.

CRD Pump Area

Fires in the CRD pump area contributes about 5 percent to the base IPEEE fire CDF. The fire analysis assumes the Division II cables passing over cabinets would fail from fully developed cabinet fires, which is assumed to cause a complete failure of Division II equipment. The change in CDF or CCDP for this area is expected to be negligible when calculating the change due to EPU implementation because the risk contribution is due to hardware failures.

Diesel Generator (Channel B) Room

Fires in this room contributes about 5 percent of the base IPEEE fire CDF. For the same reasons as presented for the Diesel Generator A Room above, the change in CDF or CCDP for this room is expected to be negligible when calculating the change due to EPU implementation.

The licensee’s principal conclusion from their fire evaluations is that the changes made to the internal events PRA model would have a minor or negligible impact on the fire CDF since the major HCGS PRA model changes did not impact the fire ignition frequencies, the location of mitigation equipment or cable routing, or the fire barriers. If this had been a risk-informed license application, the staff may have pursued further the quantitative change in fire risk due to the EPU. However, the staff believes that this issue would not significantly alter the overall results or conclusions for this license amendment, since the plant modifications needed to implement the proposed EPU do not result in any significant changes to combustible loadings throughout the plant, fire area boundaries, fire detection systems, or fire suppression systems; and the EPU-related PRA modeling changes are considered to have a negligibly small impact on fire CDF. Further, the staff believes that the overall fire CDF would be less than the IPEEE value due to the numerous enhancements to the HCGS internal events PRA model. Safety insights from the licensee’s fire risk evaluation does not raise the concern of adequate protection. Therefore, the staff concludes that there are no issues concerning fire risk that rebut the presumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements.

2.13.2.2.2.2 Full-Power Level 1 Seismic Risk Evaluation

The HCGS plant risk due to seismic events was evaluated in 1997 as part of the IPEEE by using a seismic PRA that considered the site-specific seismic hazard, seismically induced equipment failures, random equipment failures, and human actions. The IPEEE seismic CDF is presented as 3.6×10^{-6}/year if the Lawrence Livermore National Laboratory (LLNL) seismic hazard curve for the site is used.

The licensee stated that the seismic risk evaluation performed for the IPEEE had not been updated for the post-EPU plant. The staff observes that the seismic risk evaluation uses four types of information and data:

1. Earthquake occurrence frequencies (i.e., site-specific seismic hazard);
2. Equipment and structure seismic fragilities;
3. The internal event PRA logic model (which is adapted to create seismic accident sequences); and
4. Non-seismic failure probabilities (e.g., component failure rates, human actions).

Clearly, the site-specific seismic hazard is not affected by the proposed EPU because seismic hazard is determined by the geology surrounding the site. The staff believes that it is reasonable to assume that the proposed EPU does not change either the equipment or structure fragilities because there have been no significant changes to equipment layout or mounting.

In response to a staff question, the licensee identified the significant changes made to the internal events PRA model since completion of the IPEEE seismic risk evaluation. The licensee indicated that substantial changes had been made (e.g., update of the event tree accident sequence modeling, incorporation of realistic success criteria based on thermal-hydraulic analyses, revision of the HRA, revision of the fault tree analyses to reflect plant modification, and update of component failure rates and common-cause failure parameters). Qualitatively, it appears that these internal events PRA model changes and parameter updates would result in less impact from seismic events than estimated for the IPEEE since the internal events CDF has been reduced by about a factor of five, from the original IPE value of 4.6×10^{-5}/year to the current value of 9.42×10^{-6}/year (pre-EPU), while the EPU-related changes have only increased the internal events CDF by about 7 percent to 1.01×10^{-6}/year (post-EPU).

In response to a staff question, the licensee described the impact of the EPU on the top five seismic sequences, which represent approximately 95% of the IPEEE seismic CDF. The changes in the dominant seismic contributors as a result of the change in power level from the pre-EPU to the EPU configuration are described below.

Sequence SDS-36 (S-IC1)

This sequence is a seismic-induced failure of all four divisions of 1E 120V AC instrumentation distribution panels 1A/B/C/DJ481. This sequence contributes to 69.4% of the base IPEEE seismic CDF. This sequence is assumed to lead directly to core damage due to seismic-induced loss of RPV injection and containment heat removal support systems. Changes to the Hope Creek PRA model since the IPEEE have no impact on this seismic IPEEE sequence.

Sequence SDS-37 (S-DC)

This sequence is a seismic-induced failure of 1E power to all four 125V DC distribution panels 1A/B/C/D-D-417. This sequence contributes to 12.2% of the base IPEEE seismic CDF. This sequence is assumed to lead directly to core damage due to seismic-induced loss of RPV injection and containment heat removal support systems. Changes to the Hope Creek PRA model since the IPEEE have no impact on this seismic IPEEE sequence.

Sequence SDS-26 (S-OP-HP)

This sequence involves a seismic-induced loss of offsite power, seismic-induced failure of 1E 250V DC (high pressure injection), and random failures, resulting in core damage. This sequence contributes to 5.3% of the base IPEEE seismic CDF. The random failures that cause core damage are dominated by reactor depressurization failures that result in inadequate ECCS injection or emergency diesel generator (EDG) failures that result in station blackout. Potential impacts on the seismic CDF are as follows:

- Success criteria for manual RPV depressurization changed from requiring 1 of 14 SRVs (pre-EPU) to 2 of 14 SRVs (post-EPU). Due to the large number of redundant SRVs to perform the manual RPV depressurization function, the change in success criteria has a negligible impact on the seismic risk evaluation for the EPU configuration.
- Changes since the IPEEEE to the SACS success criteria to support EDG cooling could potentially increase the CDF for this sequence.

The licensee also stated that enhancements to the HRA methods have not significantly altered the operator failure probability for manual RPV depressurization and there have been no significant PRA changes to the EDG system operation or configuration. Further, the licensee indicated that the CDF for this sequence would be reduced based on industry trends and studies that show decreases in both the EDG random failure and CCF probabilities. No other changes to the HCGS internal events PRA model since the IPEEE were judged to have an impact on this sequence and the licensee stated that the CCDP is expected to be similar for both the EPU and pre-EPU conditions (i.e., to increase or decrease based on plant and model changes by the same amount for both cases).

Sequence SDS-35 (S-IC2)

This sequence is a seismic-induced failure of all four divisions of 1E 120V AC instrumentation distribution panels 1A/B/C/DJ482. This sequence contributes to 4.4% of the base IPEEE seismic CDF. The failure of the 1A/B/C/DJ482 panels results in the failure of various 1E logic cabinets, causing a substantial loss of automatic actuation of 1E equipment, including diesel generator load sequencing and automatic primary containment isolation system signals. However, manual operation of this equipment and manual diesel generator loading is still possible and procedural guidance is available. Crediting this operator action could reduce the CDF for this seismic scenario, but the HCGS IPEEE identified this as a conservatism in the IPEEE model. No other changes to the HCGS internal events PRA model since the IPEEE were judged to have an impact on this seismic IPEEE sequence and the licensee stated that the CCDP is expected to be similar for both the EPU and pre-EPU conditions (i.e., to increase or decrease based on plant and model changes by the same amount for both cases).

Sequence SDS-18 (S-OP)

This sequence is a seismic-induced loss of offsite power with subsequent random failures that results in core damage. This sequence contributes to 3.6% of the base IPEEE seismic CDF. The random failures are dominated by failure of the EDGs and their support systems, which results in station blackout. Similar to Sequence SDS-26, there have been no significant PRA changes to the EDG system operation or configuration. Further, the licensee indicated that the CDF for this sequence would be reduced based on industry trends and studies that show decreases in both the EDG random failure and CCF probabilities. No other changes to the HCGS internal events PRA model since the IPEEE were judged to have an impact on this sequence and the licensee stated that the CCDP is expected to be similar for both the EPU and pre-EPU conditions (i.e., to increase or decrease based on plant and model changes by the same amount for both cases).

The licensee's principal conclusion from their seismic evaluations is that no unique or new seismic vulnerabilities were identified for the HCGS. If this had been a risk-informed license application, the staff may have pursued further the quantitative change in seismic risk due to the EPU. However, the staff believes that this issue would not significantly alter the overall results or conclusions for this license amendment, since the plant modifications needed to implement the proposed EPU do not result in any significant changes to equipment layout or mounting; and the EPU-related PRA modeling changes are considered to have a negligibly small impact on seismic CDF. Further, the staff believes that the overall seismic CDF would be less than the IPEEE value due to the numerous enhancements to the HCGS internal events PRA model. Safety insights from the licensee's seismic risk evaluation does not raise the concern of adequate protection. Therefore, the staff concludes that there are no issues concerning seismic risk that rebut the presumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements.

2.13.2.2.2.3 Full-Power Level 1 Other External Events Risk Evaluation

In addition to internal fires and seismic events, the HCGS IPEEE analyzed a variety of other external hazards:

- High winds/tornadoes
- External floods
- Transportation and nearby facility accidents
- Other external hazards

The HCGS IPEEE analysis of high winds, tornadoes, external floods, transportation accidents, nearby facility accidents, and other external hazards was accomplished by reviewing the plant environs against regulatory requirements regarding these hazards. Based on this review, it was concluded that HCGS meets the applicable NRC SRP requirements and therefore has an acceptably low risk with respect to these hazards.

The NRC staff finds that the licensee's evaluation of the impact of the proposed EPU on other external event risk is reasonable because it is based on a methodology previously accepted by the staff for use in IPEEEs and EPU risk evaluations. The staff concludes that there are no issues concerning other external events that rebut the presumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements.

2.13.2.2.3 Total Full-Power Level 1 Risk Evaluation

The staff finds that, for internal events, minor impacts related to implementation of the EPU were identified and evaluated by the licensee, involving initiating event frequencies, component reliability, success criteria, and operator actions. The staff also finds that the risk increases due to these impacts under the EPU conditions are expected to be very small. The staff also finds that the risk impacts from external events under EPU conditions are expected to be very small.

2.13.2.3 Full-Power Level 2 Risk Evaluation

The licensee maintains a limited-scope, full-power, internal-events Level 2 PRA that estimates LERF. The following table compares and contrasts the features of the HCGS limited scope Level 2 PRA model with the simplified LERF model contained in NUREG/CR-6595, "An Approach for Estimating the Frequencies of Various Containment Failure Modes and Bypass Events." The licensee has not made any quantitative estimates of LERF associated with internal fires, seismic, high winds, floods, and other (HFO) events, or shutdown accidents.

As indicated in the following table, the licensee's limited-scope Level 2 PRA is an improvement over the simplified LERF models provided in NUREG/CR-6595:

Features of the Hope Creek Limited-Scope Level 2 PRA Model		
Modeling Differences	HCGS	NUREG/CR-6595
Integrated Level 1 and Level 2 model	yes	no
Dependencies explicitly carried through the Level 1 and Level 2 models, and treated by Boolean logic	yes	no
Level 2 branch probabilities determined using fault trees that are integrated into the Level 1 PRA model	yes	no
HRA explicitly modeled to account for dependencies on the Level 1 sequences	yes	no
Plant-specific thermal-hydraulic analyses	yes	no

The HCGS limited-scope Level 2 PRA model defines a “large, early release” as a radionuclide release that occurs less than six hours after the initiating event and involves a release of greater than or equal to 10 percent of the cesium iodide inventory in the reactor core.

The licensee stated that the change in LERF due to the proposed EPU is primarily due to the change in the CDF. None of the plant modifications needed to implement the proposed EPU significantly alter the plant’s capability to mitigate the consequences of a core-damage accident. This mitigation capability includes:

- Containment flooding to provide core cooling
- Containment spray system for scrubbing fission products and cooling core debris
- The containment capability (ultimate failure pressure)
- The RB as a fission product retention barrier (not credited in the PRA)
- RHR system for containment cooling

The proposed EPU does create some small changes in the accident progression timing that result from the increased decay heat. However, in response to a staff question, the licensee stated that none of the late releases were reclassified as early release as a result of the proposed EPU.

The licensee provided an estimate of the pre-EPU LERF, post-EPU LERF, and the change in LERF for internal initiating events. The pre-EPU LERF is stated as being about 2×10^{-7}/year and the post-EPU LERF is about 3×10^{-7}/year, with the change being about 6×10^{-8}/year.

A Monte Carlo analysis of the parametric uncertainties determined that the fifth percentile of the post-EPU LERF due to internal initiators is about 9×10^{-8}/year, and that the ninety-fifth percentile is about 7×10^{-7}/year. The licensee observed that the change in the full-power internal event LERF due to the proposed EPU lies inside this estimated uncertainty range.

The NRC staff finds that the licensee's evaluation of the impact of the proposed EPU on LERF is reasonable because it is based on a methodology previously accepted by the staff for use in risk-informed submittals and EPU risk evaluations. Since the LERF risk metrics satisfy the risk acceptance guidelines in RG 1.174, the staff concludes that the change in LERF due to the proposed EPU is very small and that there are no issues concerning containment performance that rebut the presumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements.

2.13.2.4 Shutdown Risk Evaluation

The licensee provided a qualitative assessment of the impact of the proposed EPU on shutdown plant risk because it does not have a PRA model which addresses low power and shutdown operating modes.

At HCGS, shutdown risk is managed in accordance with an outage management program and outage risk assessment procedures. These procedures provide a process for managing and assessing outage risk for both planned and forced outages. The process is based on NUMARC 91-06, Guidelines for Industry Actions to Assess Shutdown Management and also satisfies the requirements of the maintenance rule (Title 10 of the *Code of Federal Regulations* 50.65). The licensee uses the outage risk assessment and management (ORAM) computer code to assist in the management of risk during shutdowns. The ORAM model contains the safety functional assessment trees (SFATs) used to assess the configuration risk associated with each key safety function, along with the fault trees (FT), user variables (UV) and the plant configuration database that support them. The shutdown risk assessment process for Hope Creek monitors the following key safety functions: SDC, electrical power, inventory control, reactivity control, SFP cooling and secondary containment. Color codes (GREEN, YELLOW, ORANGE and RED) are utilized to identify risk levels based upon defense in depth considerations. Contingency plans are required to manage the risk associated with plant configurations that are categorized as ORANGE (minimum allowed defense-in-depth).

The licensee stated that the proposed EPU has no effect on the process or procedures for managing shutdown risk. Further, the proposed EPU has no direct effect on the defense in depth considerations associated with plant configuration and therefore no direct effect on any of the logic contained in the FTs or SFATs. However, the proposed EPU will increase the decay heat load following shutdown, which will affect the time interval before alternate DHR systems can be used. The decay heat level is accounted for in ORAM (UVs based on time from shut down, such as DECAYH and FPHEAT). The ORAM model is sufficiently conservative such that these variables do not need to be revised as a result of the relatively small increase in decay heat at the extended times of plant shutdown for EPU conditions.

The licensee provided the following qualitative risk assessment of the impacts of the proposed EPU on shutdown operations:

1. Increased decay heat - The additional decay heat load is not so large that new equipment is being added (for example, larger heat exchangers or an additional SDC loop) or that success criteria are changed. The existing plant equipment is sufficient to remove the additional decay heat. There is no direct effect on the ORAM FTs or SFATs, and the determination of risk based on defense in depth considerations will be unaffected by the proposed EPU.

2. Increased time to reach shutdown - With greater decay heat, it take longer in theory to cool down to the lower operational modes. However, this will not necessarily be realized in practice for normal shutdowns:

    a. While the calculated duration to reduce reactor coolant temperature to 200 F after plant shutdown increases from 9 hours to 13 hours, actual plant cool downs are typically performed more slowly and are not expected to be affected by the proposed EPU.

    b. Experience indicates that this evolution has, at times, taken up to 24 hours for pre-EPU conditions. The first part of the cool down, to approximately 80 psig, involves drawing steam from the reactor and condensing it. The heat removal capability/timing associated with this method of cooling down is not changed by the proposed EPU. The next block of time is involved with lining up, flushing, pre-warming and placing RHR in service for SDC. This also is not affected by the proposed EPU. The last block of time is involved with cooling down using RHR. One RHR heat exchanger is presently used, and this is not expected to be different after the proposed EPU is implemented. The maximum administrative cool down rate of 90 F/h will still be within the heat removal capability of one RHR heat exchanger after implementing the EPU. During this block of time, operators will be closing the bypass valve opening jack, closing the MSIVs, closing steam drains and preparing to open the head vents, etc. It is not expected that this sequence will be altered in any significant way due to implementation of the proposed EPU.

3. Longer mission times - From a PRA perspective, increased times to reach shutdown would result in longer mission times for the primary DHR components. Basic events related to test and maintenance unavailabilities (T&M events) and or failures to start (FS events) are not affected by the proposed EPU because they do not depend on the longer mission times. The basic events related to failure to run (FR events) for the normal DHR systems would be slightly affected by these increased mission times. However, plant risk is largely determined by the contribution from the T&M events and FS events. The FR events have much lower probabilities (typically one to two orders of magnitude) and the additional mission time is not significant enough to cause the FR events to become as important as either the T&M events or the FS events. Therefore, the increase in risk associated with longer mission times is insignificant.

4. Longer times before alternative DHR systems can be used - Heat-up curves are provided for outage scheduling purposes. One use of these curves is to ensure that alternate DHR systems are not placed in service before they are known to have sufficient heat removal capability to meet all requirements and limitations. However, the possibility of using these systems on an emergency basis affects the shutdown risk. A representative set of EPU heat-up curves was prepared by replacing the decay heat levels in the Refuel 12 (RF12, fall 2005) heat-up curves with decay heat levels for an EPU fuel load. These EPU heat-up curves were then superimposed over the actual RF12 heat up curves. If the various alternate DHR systems were placed in service on Day 4, the superimposed heat up curves predict no more than an additional 10°F peak fuel pool temperature, and lower additional peak temperatures when placed in service on subsequent days. The highest projected peak temperature is 175°F based on the alternate shut down cooling configuration of two RWCU pumps, one RWCU heat exchanger, and one FPC pump with an initial SACS temperature of 75°F and an initial SFP temperature of 100°F. Use of the alternate system in this off-normal situation would still provide 36°F of margin to fuel pool boiling. It is judged that this presents no significant increase in risk.

5. Shorter times to boiling - The outage management process requires the development of decay heat curves (heat-up curves) to be used in accordance with outage management and risk assessment procedures. A review and comparison of the pre-EPU and post-EPU heat-up curves mentioned above indicates that the EPU "times to boil" will generally be about 13 percent shorter. The risk significance for operator response times is discussed below.

6. Shorter time for operator responses - The effect on operator response times from time zero until cold shutdown is achieved is addressed in the full-power PRA model. The following discussion covers the times and configurations subsequent to opening the reactor head vents and entry into Operational Condition 4 (COLD SHUTDOWN). This discussion considers the reduction in postulated operator response times from the time of a postulated loss of normal DHR until the water inventory boils down to the TAF. Fuel damage is conservatively assumed to occur when water level reaches TAF.

The most limiting time and configuration for this condition is immediately after venting the reactor vessel and entering Operational Condition 4. The decay heat and initial bulk water temperature are highest and the water volume is lowest compared to later in the outage. The initial bulk water temperature is assumed to be 199°F. and water is assumed to be at normal level for entering Operational Condition 4. Calculations were performed to estimate the time to heat up the water inventory to saturated conditions at 212 °F, and then to boil down to the TAF. The earliest that this could occur for EPU decay heat levels is 13 hours from the time of shutdown. The calculation was performed using these initial conditions and was repeated for several later event times and conditions to assess the dynamics of the situation.

For the pre-EPU decay heat load, the calculated response time is 256 minutes (4 hours and 16 minutes). For the post-EPU decay heat load, the calculated response time is 223 minutes (3 hours and 43 minutes). This is a reduction of response time of 33 minutes, or approximately 13 percent . This represents the most challenging time for a loss of normal DHR to occur. At all subsequent times, the calculated times for operator response are longer than 3 hours and 43 minutes due to the natural reduction of the decay heat load and, for RFOs, the larger water inventory as the RFO progresses. The reduction in calculated response times is consistently 13 percent . The cited time reduction is not considered significant with respect to operator response when there is more than three hours to make a diagnosis and carry out the actions.

The NRC staff finds that the licensee's evaluation of the impact of the proposed EPU on shutdown risk is reasonable because it adequately addresses the review questions provided in the SRP, Chapter 19, Table III-1. The staff concludes that there are no issues concerning other external events that rebut the presumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements.

2.13.2.5 PRA Quality

One of the key elements in the use of PRA insights for integrated decision-making is the quality of the PRA. The licensee's PRA used to evaluate the risk impacts of the proposed EPU is an evolution of its IPE. The following table indicates the chronology of the HCGS PRA development, including major revisions, peer reviews, and self-assessments.

Chronology of the Hope Creek PRA Development and Review	
Activity	Date
IPE submitted to the NRC in response to GL 88-20.	May 31, 1994
NRC staff completes review of the IPE.	April 4, 1996
IPEEE submitted to the NRC in response to GL 88-20, Supplement 4.	July 31, 1997
The Boiling Water Reactor Owners Group (BWROG) conducts a pilot peer review.	1996

Chronology of the Hope Creek PRA Development and Review	
Activity	Date
NRC staff completes review of the IPEEE.	July 26, 1999
Licensee revises PRA model to address the significant comments of BWROG peer review.	1999
PRA peer review under the auspices of the BWROG Peer Certification Committee using NEI 00-02.	1999
PRA maintenance, upgrading, and self-assessment using the ASME PRA standard (ASME RA-S-2002) and NEI supplemental guidance.	2003
PRA maintenance, upgrading, and self-assessment to support the proposed EPU application using Addendum B to the ASME PRA standard (ASME RA-Sb-2005) and Revision 0 of Regulatory Guide 1.200 (which had been issued for trial use).	2005

In response to a staff question, the licensee provided documentation of its latest self-assessment of PRA quality, which identified the ASME Supporting Requirements that were not met at Capability Category 2 and discussed the impact of the identified deficiencies on the EPU-related risk insights. The staff has reviewed this information and concludes that the self-assessment is objective and unbiased, and that the deficiencies identified by the licensee during the self-assessment do not substantially affect the EPU-risk insights developed by the licensee.

The NRC staff finds that the licensee has met the intent of RG 1.174 (Sections 2.2.3 and 2.5), SRP Section 19.2 (Section III.2.2.4), and SRP Section 19.1, and that the HCGS PRA has sufficient scope, level of detail, and technical adequacy to support the risk evaluation of the proposed EPU.

Conclusion

The NRC staff has reviewed the licensee’s assessment of risk implications associated with the implementation of the proposed EPU and concludes that the licensee has adequately modeled and/or addressed the potential impacts associated with the implementation of the proposed EPU. The NRC staff further concludes that the results of the licensee’s risk analysis indicate that the risks associated with the proposed EPU are acceptable and do not create the “special circumstances” described in Appendix D of SRP Section 19.2. Therefore, the NRC staff finds the risk implications of the proposed EPU acceptable.

3.0 FACILITY OPERATING LICENSE AND TECHNICAL SPECIFICATION CHANGES

To achieve the EPU, the licensee proposed the following changes to the Facility Operating License (FOL) and TSs for Hope Creek.

3.1 Facility Operating License

Operating License Condition 2.C.(1)

The licensee proposed to change the maximum power level from 3,339 MWt to 3,840 MWt.

This change reflects the proposed 15% increase in the thermal power level for the plant and is consistent with the licensee's supporting safety analyses. Therefore, the NRC staff finds the proposed change acceptable.

Operating License Condition 2.C.(11)

The following is the current operating license condition 2.C.(11): "The facility shall not be operated with reduced feedwater temperature for the purpose of extending the normal fuel cycle. After the first operating cycle, the facility shall not be operated with a feedwater heating capacity that would result in a rated power feedwater temperature less than 400^{o}F unless analyses supporting such operation are submitted by the licensee and approved by the staff."

The licensee proposed to change the current license condition to the following: The facility shall not be operated with reduced FW temperature for the purpose of extending the normal fuel cycle unless analyses supporting such operation are submitted by the licensee and approved by the staff.

The HCGS design FW temperature at CPPU conditions is 431.6^{o}F. HCGS has been evaluated for operation with a FW temperature reduction of approximately 23^{o}F from the design FW temperature (minimum assumed FW temperature of 409^{o}F).

The analyses performed by the licensee and documented in its September 18, 2006 submittal support operation with reduced FW temperature and allow continued operation during FW system maintenance, if required. For future operating cycles, the reload process will continue to address the effects of reduced FW temperature on the cycle specific safety analyses. HCGS will not operate with reduced FW temperature for the purpose of extending cycle energy capability beyond the normal end-of-cycle condition without prior NRC review and approval. The staff finds this proposed change acceptable.

Operating License Condition 2.C.(19)

The licensee proposed to add the following new license condition:

> Leak rate tests required by Surveillance Requirement 4.6.1.2.a and 4.6.1.2.h to be performed in accordance with the Primary Containment Leakage Rate Testing Program are not required to be performed until their next scheduled performance, which is due at the end of the first test interval that begins on the date the test was last performed prior to implementation of Amendment No. [XXX].

SR 4.6.1.2.a requires that primary containment leakage rates be demonstrated in accordance with the Primary Containment Leakage Rate Testing Program. The testing program is required by 10 CFR 50.54(o) and 10 CFR 50 Appendix J and is described in TS 6.8.4.f. Test intervals are established on a performance basis in accordance with 10 CFR 50 Appendix J, Option B.

SR 4.6.1.2.h requires that all containment isolation valves in hydrostatically tested lines which penetrate the primary containment be leak tested at least once per 18 months. The combined leakage rate is limited to less than or equal to 10 gpm when tested at 1.10 times Pa, the calculated peak containment pressure (Pa).

The Type A integrated leak rate test (ILRT) and the Type B and C local leak rate tests are performed at the calculated peak containment pressure (P_a). P_a increases to 50.6 psig for the proposed EPU, and TS 6.8.4.f is being revised to reflect the change. The hydrostatic leak testing required by SR 4.6.1.2.h is performed at 1.10 times Pa. The required hydrostatic test pressure increases from 52.9 psig to 55.7 psig for the EPU. However, with substantial margin to the leakage rate acceptance limits based upon current leak rate test results, it is not necessary to re-perform all of the leak rate tests at the higher pressures before implementation of the proposed EPU.

Proposed License Condition 2.C.(19) would allow leak rate tests required by SR 4.6.1.2.a and SR 4.6.1.2.h to be considered to be performed per SR 4.0.1, upon implementation of the license amendment approving the proposed EPU, until the next scheduled performance. This would preclude having to perform the affected leak rate tests before their next scheduled performance solely for the purpose of documenting compliance. The allowance provided in License Condition 2.C.(19) would not supersede that aspect of SR 4.0.1 that governs cases where it is believed that, if the SR were performed, it would not be met. Performance of the leak rate tests merely to document compliance would unnecessarily divert resources, interfere with plant operations, potentially incur additional personnel dose, and would not improve plant safety. The staff finds this proposed change acceptable.

Operating License – Enclosures

During the processing of Amendment 173, dated January 24, 2008 (ML073450034), a typographical error was introduced under the “Enclosures:” section of the facility operating license. Currently, it reads the following:

> Appendix A – Technical Specifications (NUREG-1201)

The correct NUREG is NUREG-1202; there was a typographical error introduced in the processing of Amendment 173. To correct the typographical error, it will be changed to read the following:

> Appendix A – Technical Specifications (NUREG-1202)

This is an administrative change and the staff finds this proposed change acceptable.

3.2 Technical Specifications

TS 1.35 - RATED THERMAL POWER

The licensee proposed to change Technical Specification (TS) 1.35, "RATED THERMAL POWER" from the currently licensed RTP of 3,339 MWt to 3,840 MWt. The licensee proposed RTP change to 3,840 MWt is consistent with the Facility Operating License Condition 2.C.(1). The change reflects the actual value in the proposed application and is consistent with the results of the NRC staff's review. Therefore, the NRC staff finds the proposed change acceptable based on Section 2 above.

TS 2.1.1 -THERMAL POWER, Low Pressure or Low Flow, and the associated Action

The licensee proposed to revise the value of the thermal monitoring thresholds to 24 percent.

The existing 25 percent of RTP limit for the TS SL is based on generic analyses, evaluated up to approximately 50 percent of original RTP for the plant design with highest average bundle power (the BWR6) for all of the BWR product lines. This average bundle power (at 100 percent RTP) was 4.8 MWt. For the Hope Creek EPU, the average bundle power is 5.03 MWt. Therefore, the SL Percent RTP basis for EPU conditions is reduced to 24 percent RTP. Therefore, the staff finds the proposed change acceptable.

TS 2.1.2 -THERMAL POWER, High Pressure and High Flow

The licensee proposed to change the MCPR from 1.06 to 1.08 for two recirculation loop operation and from 1.08 to 1.10 for single recirculation loop operation. Based on the staff review described in Section 2.8, the staff finds the proposed change acceptable.

Table 2.2.1-1 - Reactor Protection System Instrumentation Setpoints, Functional Unit 2.a

The licensee proposed to revise the APRM Neutron Flux - Upscale, Setdown Trip Setpoint to 14 percent and to revise the AV to 19 percent

The value for the TS SL for the reduced pressure or low core flow condition is established to satisfy the fuel thermal limits monitoring requirements. Because the thermal margin monitoring requirement is reduced from 25 percent to 24 percent, the APRM Scram Setdown AV is reduced the same amount, i.e., from 20 percent to 19 percent. Similarly, APRM Neutron Flux upscale, setdown trip setpoint is reduced from 15 percent to 14 percent. Therefore, the staff finds the proposed change acceptable.

Table 2.2.1-1 - Reactor Protection System Instrumentation Setpoints, Functional Unit 2.b.1

The licensee proposed to revise the APRM Flow-Biased Simulated Thermal Power Upscale Trip Setpoint to:
$\leq$ 0.57 (w – delta w)+ 58%.

The licensee proposed to revise the Allowable Value to:
$\leq$ 0.57 (w – delta w) + 61%.

The NTSPs were adjusted by the same difference as the changes in the AVs; this allows the same uncertainties. Therefore, the staff finds the proposed change acceptable.

LCO 3.1.4.1 - Rod Worth Minimizer, Applicability

The licensee proposed to revise the value of the thermal power level for required RWM operability to 8.6 percent.

The RCIS Rod Pattern Controller is not applicable to Hope Creek. The RWM low power setpoint (LPSP) is used to bypass the rod pattern constraints established for the CRDA at greater than a pre-established low power level. The measurement parameter is steam flow.

This approach does not affect the limitations on the sequence of control rod movement to the absolute core power level for the LPSP associated with the requirements of the CRDA. The RWM main steam instrumentation is being replaced to provide adequate measurement range for CPPU and therefore, a new setpoint was calculated from 10 percent to 8.6 percent. The staff finds the proposed change acceptable.

LCO 3.2.1 - APLHGR, Applicability; LCO 3.2.1 - APLHGR, Action; and SR 4.2.1.a

The licensee proposed to revise the Average Planar Linear Heat Generation Rate (APLHGR) RTP thermal monitoring threshold value to 24 percent.

The existing 25 percent of RTP limit for the LCO Applicability is based on generic analyses, evaluated up to approximately 50 percent of original RTP for the plant design with highest average bundle power (the BWR6) for all of the BWR product lines. This average bundle power (at 100 percent RTP) was 4.8 MWt. For the Hope Creek EPU, the average bundle power is 5.03 MWt. Therefore, the LCO Applicability for EPU conditions is reduced to 24 percent RTP. The proposed changes to the Action and SR maintain consistency with the change to the LCO Applicability. The staff finds the proposed change acceptable.

LCO 3.2.3 - MCPR Applicability; LCO 3.2.3 - MCPR, Action b; and SR 4.2.3.a

The licensee proposed to revise the MCPR RTP thermal monitoring threshold value to 24 percent.

The existing 25 percent of RTP limit for the LCO Applicability is based on generic analyses, evaluated up to approximately 50 percent of original RTP for the plant design with highest average bundle power (the BWR6) for all of the BWR product lines. This average bundle power (at 100 percent RTP) was 4.8 MWt. For the Hope Creek EPU, the average bundle power is 5.03 MWt. Therefore, the LCO Applicability for EPU conditions is reduced to 24 percent RTP. The proposed changes to the Action and SR maintain consistency with the change to the LCO Applicability. The staff finds the proposed change acceptable.

LCO 3.2.4 - LHGR, Applicability; LCO 3.2.4 - LHGR, Action; and SR 4.2.4.a

The licensee proposed to revise the LHGR RTP thermal monitoring threshold value to 24 percent.

The existing 25 percent of RTP limit for the LCO Applicability is based on generic analyses, evaluated up to approximately 50 percent of original RTP for the plant design with highest average bundle power (the BWR6) for all of the BWR product lines. This average bundle power (at 100 percent RTP) was 4.8 MWt. For the Hope Creek EPU, the average bundle power is 5.03 MWt. Therefore, the LCO Applicability for EPU conditions is reduced to 24 percent RTP. The proposed changes to the Action and SR maintain consistency with the change to the LCO Applicability. The staff finds the proposed change acceptable.

Table 3.3.1-1 Reactor Protection System Instrumentation Table Notations, Note (j), and TS Table 3.3.4.2-1- EOC - RPT Trip instrumentation, Note (b)

The licensee has revised the reactor thermal power (RTP) value to 24 percent. The AL for the EPU is maintained at the same absolute power as the current setpoint. The licensee has reduced this value further in the conservative direction. Based on this, the 24 percent RTP value is acceptable to the staff. The staff has reviewed this analysis and finds the proposed change acceptable.

Table 4.3.1.1-1, Reactor Protection System Instrumentation Surveillance Requirements, Note (d)

The licensee has revised note (d) for the TS Table 4.3.1.1-1 to change thermal power ≥25 percent of rated thermal power to ≥24% of rated thermal power. The 25 percent RTP value is based on a generic analysis for all BWR plants with the highest average bundle power for 100 power original power level. However, the proposed EPU average bundle power for HCGS is higher than that previously assumed in the analysis. The new 24 percent RTP was established based on the new average bundle power. The analysis with the new bundle power is reviewed and accepted by the staff and is documented in Section 2.8, “Reactor Systems,” of this safety evaluation. Based on this, the staff finds the proposed change acceptable.

Table 3.3.2-2 - Isolation Actuation Instrumentation Setpoints, Trip Function 3.d

The licensee has revised the trip setpoint and AV for main steam line flow instrumentation from 108.7 psid and 111.7 psid to 162.8 psid and 169.3 psid respectively. The AL in percent of rated steam flow is unchanged. The licensee has calculated the instrument setpoint and AV with an acceptable methodology as discussed in Section 2.4, “Instrumentation and Controls;” therefore, the staff finds the proposed change acceptable.

LCO 3.3.4.2 - End-of-Cycle Recirculation Trip System Instrumentation, Applicability

The licensee has revised the applicability of this LCO to thermal power greater than or equal to 24 percent of RTP. The proposed value is more conservative than the current value in terms of absolute power. The 25 percent RTP value is based on a generic analysis for all BWR plants with the highest average bundle power for 100 power original power level. However, the proposed EPU average bundle power for HCGS is higher than that previously assumed in the analysis. The new 24 percent RTP was established based on the new average bundle power.

The analysis with the new bundle power is reviewed and accepted by the staff and is documented in Section 2.8, "Reactor Systems," of this safety evaluation. Based on this, the staff finds the proposed change acceptable.

Table 3.3.6-2 - Control Rod Block Instrumentation Setpoints, Trip Function 2.a, and Table 3.3.6-2 -Control Rod Block Instrumentation Setpoints, Trip Function 2.d

The licensee has revised the trip setpoint and AV for Flow Biased Neutron Flux-Upscale, (Functional Unit 2.a) and Neutron Flux - Upscale, Startup (Functional Unit 2.d). Based on the staff's review, the staff finds the proposed change acceptable.

LCO 3.3.11 - Oscillation Power Range Monitor Instrumentation, Applicability; and LCO 3.3.11, Action c

The licensee has revised the RTP from 25 percent to 24 percent. The 25 percent RTP value is based on a generic analysis for all BWR plants with the highest average bundle power for 100 power original power level. However, the proposed EPU average bundle power for HCGS is higher than that previously assumed in the analysis. The new 24 percent RTP was established based on the new average bundle power. The analysis with the new bundle power is reviewed and accepted by the staff and is documented in Section 2.8, "Reactor Systems," of this safety evaluation. Based on this, the staff finds the proposed change acceptable.

SR 4.3.11.5

The licensee has revised the thermal power to 26.1 percent from 30 percent RTP. The licensee has justified this change based on the fact that this new value maintains the same absolute power/flow region boundaries for the OPRM trip-enabled region. The analysis is reviewed and accepted by the staff and is documented in Section 2.8, "Reactor Systems," of this safety evaluation. Based on this, the staff finds the proposed change acceptable.

LCO 3.4.1.1 - Recirculation Loops, Action a.l.b; and SR 4.4.1.1.1.a

The licensee proposed to change the maximum power for SLO to 60.86 percent. The proposed changes maintain the existing licensed region for SLO. The analysis is reviewed and accepted by the staff and is documented in Section 2.8, "Reactor Systems," of this safety evaluation. Based on this, the staff finds the proposed change acceptable.

LCO 3.4.1.2 - Jet Pumps, SRs 4.4.1.2.a and 4.4.1.2.c

The licensee proposed to change 25 percent RTP to 24 percent RTP. The proposed changes are consistent with changes to the applicability of power distribution limits for ECCS performance analyses. The analysis is reviewed and accepted by the staff and is documented in Section 2.8, "Reactor Systems," of this safety evaluation. Based on this, the staff finds the proposed change acceptable.

LCO 3.6.1.2.c - Primary Containment Leakage

The licensee proposed to change 48.1 psig to 50.6 psig. The proposed change reflects the updated containment pressure response. Short-term and long-term containment analyses results are reported in the UFSAR. The short-term analysis is directed primarily at determining the drywell pressure response during the initial blowdown of the reactor vessel inventory to the containment following a large break 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. Based on the staff's evaluation in Section 2.6, the staff finds the proposed change acceptable.

LCOs 3.6.1.2.d and 3.6.1.2.e - Primary Containment Leakage and SR 4.6.1.2.g

The licensee proposed to change 52.9 psig to 55.7 psig.

The proposed changes reflect the updated containment pressure response. Short-term and long-term containment analyses results are reported in the UFSAR. The short-term analysis is directed primarily at determining the drywell pressure response during the initial blowdown of the reactor vessel inventory to the containment following a large break 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. Based on the staff's evaluation in Section 2.6, the staff finds the proposed change acceptable.

LCO 3.7.7 - Main Turbine Bypass System, Applicability and Action

The licensee proposed to change 25 percent RTP to 24 percent RTP. The proposed change maintains consistency with the changes to TS 2.1.1 and LCOs 3.2.1, 3.2.3 and 3.2.4. The analysis is reviewed and accepted by the staff and is documented in Section 2.8, "Reactor Systems," of this safety evaluation. Based on this, the staff finds the proposed change acceptable.

LCO 3.10.2 - Rod Worth Minimizer

The licensee proposed to change 10 percent RTP to 8.6 percent RTP. Proposed change maintains consistency with proposed changes to LCO 3.1.4.1. The analysis is reviewed and accepted by the staff and is documented in Section 2.8, "Reactor Systems," of this safety evaluation. Based on this, the staff finds the proposed change acceptable.

TS 6.8.4.f - Primary Containment Leakage Rate Testing Program

The licensee proposed to change 48.1 psig to 50.6 psig.

The proposed change reflects the updated containment pressure response. Short-term and long-term containment analyses results are reported in the UFSAR. The short-term analysis is directed primarily at determining the drywell pressure response during the initial blowdown of the reactor vessel inventory to the containment following a large break 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. Based on the staff's evaluation in Section 2.6, the staff finds the proposed change acceptable.

3.3 License Conditions

License Condition 2.C.(20) Top Guide Beams

Until there is more detailed guidance regarding the inspections of the top guide beams or the issue is resolved by the BWRVIP generically, the following license condition applies to Hope Creek to preclude the loss of the component's intended function:

> 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 5 percent of the population within six years, and 10 percent of the total population of cells within twelve 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 first RFO following EPU operation.

License Condition 2.C.(21) Vibration Acceptance Criteria for SRVs

PSEG Nuclear LLC shall provide the Level 1 main steam safety relief valve vibration acceptance criteria to the NRC staff prior to increasing power above 3339 MWt.

License Condition 2.C.(22) Steam Dryer

This license condition provides for monitoring, evaluating, and taking prompt action in response to potential adverse flow effects as a result of power uprate operation on plant structures, systems, and components (including verifying the continued structural integrity of the steam dryer).

1. The following requirements are placed on initial operation of the facility at power levels above 3339 MWt to 3840 MWt for the power ascension:

    a. PSEG Nuclear LLC shall monitor hourly the main steam line (MSL) strain gage data during power ascension above 3339 MWt for increasing pressure fluctuations in the steam lines.

    b. PSEG Nuclear LLC shall hold the facility at 105 percent and 110 percent of 3339 MWt to collect data from the MSL strain gages required by Condition 1.a, conduct plant inspections and walkdowns, and evaluate steam dryer performance based on these data; shall submit the evaluation to the NRC staff upon completion of the evaluation; and shall not increase power above each hold point until 96 hours after submitted to the NRC.

    c. If any frequency peak from the MSL strain gage data exceeds any of the Level 1 limit curves, PSEG Nuclear LLC shall return the facility to a lower power level at which the limit curve is not exceeded. PSEG Nuclear shall resolve the uncertainties in the steam dryer analysis, evaluate the continued structural integrity of the steam dryer, and submit that evaluation to the NRC staff.

d. In addition to evaluating the MSL strain gage data, PSEG Nuclear LLC shall monitor reactor pressure vessel water level instrumentation and MSL piping accelerometers on an hourly basis during power ascension above 3339 MWt. If resonance frequencies are identified as increasing above nominal levels in proportion to strain gage instrumentation data (including consideration of the EPU bump-up factor), PSEG Nuclear LLC shall stop power ascension, evaluate the continued structural integrity of the steam dryer, and submit that evaluation to the NRC staff.

2. PSEG Nuclear LLC shall implement the following actions for the initial power ascension at power levels above 3339 MWt to 3840 MWt:

a. In the event that acoustic signals are identified that challenge the limit curves during power ascension above 3339 MWt, PSEG Nuclear LLC shall evaluate dryer loads and re-establish the limit curves based on the new strain gage data, and shall perform a frequency-specific assessment of ACM uncertainty at the acoustic signal frequency including application of 65 percent bias error and 10 percent uncertainty to all the SRV acoustic resonances.

b. After reaching 111.5 percent of 3339 MWt, PSEG Nuclear LLC shall obtain measurements from the MSL strain gages and establish the steam dryer flow-induced vibration load fatigue margin for the facility, update the dryer stress report, and re-establish the limit curves with the updated ACM load definition, which will be submitted to the NRC staff.

c. After reaching 115 percent of 3339 MWt, PSEG Nuclear LLC shall obtain measurements from the MSL strain gages and establish the steam dryer flow-induced vibration load fatigue margin for the facility, update the dryer stress report, and re-establish the limit curves with the updated ACM load definition, which will be submitted to the NRC staff.

d. During power ascension above 3339 MWt, if an engineering evaluation is required because a Level 1 acceptance criterion is exceeded, PSEG Nuclear LLC shall perform the structural analysis to address frequency uncertainties up to ±10 percent and assure that peak responses that fall within this uncertainty band are addressed.

e. PSEG Nuclear LLC shall revise plant procedures 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 BWRVIP-139; and to identify the NRC Project Manager for the facility as the point of contact for providing power ascension testing information during power ascension.

f. PSEG Nuclear LLC shall submit the final EPU steam dryer load definition for the facility to the NRC staff upon completion of the power ascension test program.

g. PSEG Nuclear LLC shall submit the flow-induced vibration related portions of the EPU startup test procedure to the NRC staff, including methodology for updating the limit curves, prior to initial power ascension above 3339 MWt.

3. PSEG Nuclear LLC shall prepare the EPU startup test procedure to include:

   a. the stress limit curves to be applied for evaluating steam dryer performance;

   b. specific hold points and their duration during EPU power ascension;

   c. activities to be accomplished during hold points;

   d. plant parameters to be monitored;

   e. inspections and walk downs 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; and

   i. verification of the completion of commitments and planned actions specified in its application and all supplements to the application in support of the EPU license amendment request pertaining to the steam dryer prior to power increase above 3339 MWt.

   PSEG Nuclear LLC shall provide the related EPU startup test procedure sections to the NRC staff prior to increasing power above 3339 MWt.

4. The following key attributes of the program for verifying the continued structural integrity of the steam dryer shall not be made less restrictive without prior NRC approval:

   a. During initial power ascension testing above CLTP, each test plateau increment shall be approximately 5 percent of 3339 MWt;

   b. Level 1 performance criteria; and

   c. The methodology for establishing the stress spectra used for the Level 1 and Level 2 performance criteria.

   Changes to other aspects of the program for verifying the continued structural integrity of the steam dryer may be made in accordance with the guidance of NEI 99-04.

5. During the first scheduled refueling outage after Cycle 15 and during the first two scheduled refueling outages after reaching full EPU conditions, a visual inspection shall be conducted of all accessible, susceptible locations of the steam dryer in accordance with BWRVIP-139 inspection guidelines.

6. The results of the visual inspections of the steam dryer shall be reported to the NRC staff within 90 days following startup from the respective refueling outage. The results of the power ascension testing to verify the continued structural integrity of the steam dryer shall be submitted to the NRC staff in a report within 60 days following the completion of all Cycle 15 power ascension testing. A supplement shall be submitted within 60 days following the completion of all EPU power ascension testing.

4.0 REGULATORY COMMITMENTS

The licensee made no regulatory commitments.

5.0 RECOMMENDED AREAS FOR INSPECTION

As described above, the NRC staff has conducted an extensive review of the licensee's plans and analyses related to the proposed EPU and concluded that they are acceptable. The NRC staff's review has identified the following areas for consideration by the NRC inspection staff during the licensee's implementation of the proposed EPU. 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.

1. Top guide beams.

2. Power ascension testing activities.

In addition to the recommended areas for inspection listed above, NRC Inspection Procedure 71004, "Power Uprates," provides guidance for conducting inspections associated with power uprate amendments including considerations for selecting inspection samples.

6.0 STATE CONSULTATION

In accordance with the Commission's regulations, the New Jersey State official was notified of the proposed issuance of the amendment. The State official had comments in a letter dated April 23, 2008.[270]

The State of New Jersey had the following comments from the New Jersey Department of Environmental Protection's Bureau of Nuclear Engineering (NJ BNE): (1) NJ BNP requests that the NRC verify that the increase in reactor power from 111.5 percent to 115 percent of current reactor power will be performed in discrete steps with appropriate data collection and respective hold points in accordance with the test program stipulated by the licensee for increasing power from 100 percent to 111.5 percent of current licensed power, and (2) any references to nominal reactor pressure (1019 psia) should maintain units consistent (psia or psig).

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[270] ADAMS Accession No. ML081210379

The following is the NRC staff response to NJ BNE Comment (1):

This comment is addressed in the license conditions contained above in Section 3.3.3, where the NRC staff has stated that the conditions are from CLTP of 3339 MWt to full EPU conditions of 3840 MWt.

The following is the NRC staff response to NJ BNE Comment (2):

The NRC staff addressed this comment by revising the text on page A-10.

7.0 ENVIRONMENTAL CONSIDERATION

Pursuant to 10 CFR 51.21, 51.32, 51.33, and 51.35, a draft Environmental Assessment and finding of no significant impact was prepared and published in the *Federal Register* on October 22, 2007 (72 FR 59563). The draft Environmental Assessment provided a 30-day opportunity for public comment. The NRC staff received comments which were addressed in the final environmental assessment. The final Environmental Assessment was published in the *Federal Register* on March 11, 2008 (73 FR 13032). 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 amendment will not be inimical to the common defense and security or to the health and safety of the public.

References:

1. NRC letter from C. Grimes, NRC, to D. Walters, Nuclear Energy Institute (NEI) dated May 19, 2000, License Renewal Issue No. 98-0030, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Components" (ML003717179)

2. NRC Summary of November 13 and 14, 2006, Category 1 Meeting with PSEG Nuclear LLC, Regarding Application for Extended Power Uprate for Hope Creek Generating Station (TAC No. MD3002), dated December 15, 2006 (ML063330143).

3. NRC letter to U.S. Fish and Wildlife Service dated December 8, 2006, “Request for List of Protected Species within the Area under Evaluation for the Hope Creek Generating Station Extended Power Uprate (TAC No. MC3002),” (ML063380148).

4. NRC letter to NOAA’s National Marine Fisheries Service dated December 8, 2006, “Request for List of Protected Species within the Area under Evaluation for the Hope Creek Generating Station Extended Power Uprate (TAC No. MC3002),” (ML063380315).

5. NRC letter to William Levis, PSEG Nuclear LLC, dated February 16, 2007, “Hope Creek Generating Station - Request for Additional Information Regarding Request for Extended Power Uprate (TAC No. MD3002),” (ML070330415).

6. NRC letter to William Levis, PSEG Nuclear LLC, dated February 23, 2007, “Hope Creek Generating Station - Request for Additional Information Regarding Request for Extended Power Uprate (TAC No. MD3002),” (ML070460243).

7. NRC letter to William Levis, PSEG Nuclear LLC, dated March 2, 2007, “Hope Creek Generating Station - Request for Additional Information Regarding Request for Extended Power Uprate (TAC No. MD3002),” (ML070600611).

8. NRC letter to William Levis, PSEG Nuclear LLC, dated March 13, 2007, “Hope Creek Generating Station - Request for Additional Information Regarding Request for Extended Power Uprate (TAC No. MD3002),” (ML070680306).

9. NRC letter to William Levis, PSEG Nuclear LLC, dated April 20, 2007, “Hope Creek Generating Station - Request for Additional Information Regarding Request for Extended Power Uprate (TAC No. MD3002),” (ML070800258).

10. NRC Summary of March 2, 2007, Meeting with PSEG Nuclear LLC, on an Application for Extended Power Uprate for Hope Creek Generating Station Regarding Steam Dryer Margin (TAC No. MD3002), dated March 29, 2007 (ML070800430).

11. NRC letter to National Marine Fisheries Service dated May 3, 2007, “Explanation of Hope Creek Generating Station Extended Power Uprate and Conclusion of Informal Consultation (TAC No. MC3002),” (ML071010409).

12. NRC letter to William Levis, PSEG Nuclear LLC, dated April 20, 2007, “Hope Creek Generating Station - Request for Additional Information Regarding Request for Extended Power Uprate (TAC No. MD3002),” (ML071140091).

13. NRC letter to William Levis, PSEG Nuclear LLC, dated May 14, 2007, "Hope Creek Generating Station - Request for Additional Information Regarding Request for Extended Power Uprate (TAC No. MD3002)," (ML071240411).

14. NRC Summary of April 20, 2007, Meeting with PSEG Nuclear LLC, on an Application for Extended Power Uprate for Hope Creek Generating Station Regarding Interim Fuel Methods (TAC No. MD3002), dated May 15, 2007 (ML071240505).

15. NRC letter to William Levis, PSEG Nuclear LLC, dated May 17, 2007, "Hope Creek Generating Station - Request for Additional Information Regarding Request for Extended Power Uprate (TAC No. MD3002)," (ML071370700).

16. NRC letter to U.S. Fish and Wildlife Service dated June 13, 2007, "Explanation of Hope Creek Generating Station Extended Power Uprate and Conclusion of Informal Consultation (TAC No. MC3002)," (ML071410315).

17. NOAA Letter to NRC dated January 26, 2007, "Hope Creek Extended Power Uprate," (ML071440169).

18. NRC letter to National Marine Fisheries Service dated June 14, 2007, "Hope Creek Extended Power Uprate Essential Fish Habitat Assessment," (ML071520463).

19. NRC letter to William Levis, PSEG Nuclear LLC, dated June 7, 2007, "Hope Creek Generating Station - Request for Additional Information Regarding Request for Extended Power Uprate (TAC No. MD3002)," (ML071560348).

20. State of New Jersey Letter to NRC dated June 1, 2007, Comments regarding the Federal Register Notice dated May 3, 2007 (72 FR 24627) for the Hope Creek Extended Power Uprate, (ML071940242).

21. NRC Summary of June 28, 2007, Meeting with PSEG Nuclear LLC, Regarding an Application for Extended Power Uprate for Hope Creek Generating Station Regarding Dryer Analysis Acceptance Criteria (TAC No. MD3002), dated August 13, 2007 (ML071990528).

22. PSEG letter (LR-N07-0168) to NRC dated July 12, 2007, "Schedule for Responses to Requests for Additional Information Request for License Amendment - Extended Power Uprate" (ML072110215).

23. U.S. Fish and Wildlife Service Letter to NRC dated July 24, 2007, Hope Creek Extended Power Uprate, (ML072200498).

24. NRC letter to William Levis, PSEG Nuclear LLC, dated August 21, 2007, "Hope Creek Generating Station - Request for Additional Information Regarding Request for Extended Power Uprate (TAC No. MD3002)," (ML072320134).

25. PSEG letter (LR-N07-0218) to NRC dated August 27, 2007, "Transmittal of August 17, 2007 Extended Power Uprate Meeting Presentation Material," (ML072480515).

Attachment: List of Acronyms

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Date:

ATTACHMENT - LIST OF ACRONYMS

ACRONYM	DEFINITION
A	Amperes
AAC	alternate alternating current
AAF	acceptable as found
AAL	acceptable as left
AC	alternating current
ACM	acoustic circuit model
ACRS	Advisory Committee on Reactor Safeguards
ACS	alternate cooling system
ADAMS	Agencywide Documents Access and Management System
ADS	automatic depressurization system
AEC	Atomic Energy Commission
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	annulus pressurization
APLHGR	average planar linear heat generation rate
APRM	average power range monitor
ARAVS	auxiliary and radwaste area ventilation system
ARI	alternate rod injection
ART	adjusted reference temperature
ARTS	Average Power Range Monitor, Rod Block Monitor Technical Specifications
ASEP	Accident Sequence Evaluation Program
ASHRAE	American Society of Heating, Refrigerating and Air-Conditioning Engineers

ACRONYM	DEFINITION
ASME	American Society of Mechanical Engineers
ASP	accident sequence precursor
AST	Alternative/alternate source term
ASTM	American Society for Testing and Materials
ATWS	anticipated transient without scram
AV	allowable value
B&PV	Boiler and Pressure Vessel
BIIT	boron injection initiation temperature
BL	Bulletin
BOC	beginning of cycle
BOP	balance-of-plant
BPS	Barksdale Pressure Switches
BPWS	banked position withdrawal sequence
BSP	backup stability protection
BTP	Branch Technical Position
BTU/lbm	British thermal units per pounds mass
BWR	boiling-water reactor
BWROG	Boiling-Water Reactors Owner's Group
BWRVIP	Boiling-Water Reactors Vessels and Internals Project
CADS	containment atmosphere dilution system
cal/gm	calories per gram
CBDTM	Caused based decision tree method
CCDP	conditional core-damage probability
CCFP	conditional containment failure probability
CD	complete dependency
CDF	core damage frequency
CFD	computational fluid dynamics
CMF	cubic feet per minute

ACRONYM	DEFINITION
CFR	Code of Federal Regulations
CFS	condensate and feedwater system
ci/sec	Curies/second
CLTP	current licensed thermal power (1593 MWt)
CLTR	constant pressure power uprate licensing topical report
CO	condensation oscillation
CORL	Core operating limits report
CP	condensate pump
CPF	condensate pre-filters
CPPU	constant pressure power uprate
CPR	critical power ratio
CRAVS	control room area ventilation system
CRD	control rod drive
CRDA	control rod drop accident
CRDS	Control rod drive system
CREF	Control Room Emergency Filtration
CREFS	Control Room Emergency Filtration System
CS	core spray
CSC	containment spray cooling
CSS	core support structure
CST	condensate storage tank
CT	current transformer
CUF	cumulative usage factor
CWS	circulating water system
DBA	design-basis accident
DBLOCA	design-basis loss-of-coolant accident
DC	direct current
DCP	design change process

ACRONYM	DEFINITION
DE	Dose Equivalent
DEHC	Digital electro-hydraulic control
DHR	decay heat removal
DIVOM	delta critical power ratio (CPR) over initial CPR versus oscillation magnitude
DR	decay ratio
EAB	exclusion area boundary
ECCS	emergency core cooling system
ECP	electrochemical potential
EDG	emergency diesel generator
EFDS	equipment and floor drainage system
EFPY	effective full-power years
EHC	electrohydraulic control
ELTR1	GE Licensing Topical Report NEDC-32424P-A
ELTR2	GE Licensing Topical Report NEDC-32523P-A
EOC	end-of-cycle
EOL	end-of-life
EOP	emergency operating procedure
EOS	emergency overspeed
EPGs	emergency procedure guidelines
EPRI	Electric Power Research Institute
EPU	extended power uprate
EQ	environmental qualification
ES	extraction steam
ESF	engineered safety features
ESFAS	engineered safety features actuation system
ESFVS	engineered safety feature ventilation system
EVT	enhanced visual testing
FAC	flow-accelerated corrosion

ACRONYM	DEFINITION
FHA	fuel handling accident
FIV	flow-induced vibration
FIVE	fire induced vulnerability evaluation
FOL	Facility Operating License
FPC	fuel pool cooling
FPCCS	Fuel pool cooling and cleanup system
FPP	fire protection program
FR	Federal Register
FRI	fast recirculation increase
FRVS	Filtration recirculation and ventilation system
FRVS-RS	Filtration recirculation and ventilation system – Recirculation System
FRVS-VS	Filtration recirculation and ventilation system – Vent System
ft	feet
ft-lb	foot-pounds
FV	Fussell-Vesely
FW	feedwater
FWC	feedwater control
FWCS	Feedwater controller failure
Gd	Gadolinium
GDC	General Design Criteria (or Criterion)
GE	General Electric
GESTAR	General Electric Standard Application for Reactor Fuels
GL	Generic Letter
GNF	Global Nuclear Fuel
gpm	gallons per minute
GSU	generator set up
GWd/MTU	gigawatt days per metric ton uranium
GWd/ST	gigawatt days per short ton

ACRONYM	**DEFINITION**
GWMS	gaseous waste management systems
HCGS	Hope Creek Generating Station
HCTL	heat capacity temperature limit
HCU	hydraulic control unit
HELB	high energy line break
HEP	human error probability
HEPA	high efficiency particulate air
HgA	Mercury absolute
HP	high pressure
HPCI	high-pressure coolant injection
hr	hour
HRA	Human reliability analysis
HVAC	heating, ventilating, and air conditioning
HWC	Hydrogen water chemistry
IASCC	irradiation assisted stress-corrosion cracking
ICA	Interim Correction Action
ICPR	initial critical power ratio
ID	Inside diameter
IEEE	Institute of Electrical and Electronics Engineers
IGSCC	intergranular stress-corrosion cracking
ILPBA	instrument line pipe break accident
ILRT	integrated leak rate test
IN	Information Notice
IORV	inadvertent open relief valve
IPE	individual plant examinations
IPEEE	individual plant examinations of external events
IR	Inspection Report
ISI	inservice inspection

ACRONYM	DEFINITION
ISO-NE	Independent System Operator - New England
ISP	integrated surveillance program
KA	kiloamps
ksi	1000 pounds per square inch
kV	kilovolts
kW/ft	kilowatts per foot
LCO	limiting condition for operation
LER	licensee event report
LERF	large early release frequency
LFWH	Loss of feedwater heater
LHGR	linear heat generation rate
LLHS	light load handling system
LOCA	loss-of-coolant accident
LOFW	loss of feedwater
LOFWF	Loss of feedwater flow
LOOFP	Loss of one feedwater pump
LOOP	loss of offsite power
LP	low pressure
LPCI	low pressure coolant injection
LPRM	local power range monitor
LPSP	Low power set point
LPZ	low population zone
LRNBP	Load rejection, no bypass
LRWBP	Load rejection, with bypass
LSSS	Limited safety system setting
LTR	licensing topical report
LWMS	liquid waste management system
MAAC	Mid-Atlantic Area Council

ACRONYM	DEFINITION
MAAP	modular accident analysis program
MAPLHGR	maximum average planar linear heat generation rate
MBTU/hr	million British thermal units per hour
MCAR	“mixed core analysis report”
MCC	motor control center
MCES	main condenser evacuation system
MCNP	Monte Carlo N Particle Transport Code
MCPR	Minimum critical power ratio
MCS	main condenser system
MELLLA	maximum extended load line limit analysis
MEQ	Mechanical Equipment Qualification
MeV	Mega-electron volt
mg	milligram
Mlb/ft2	million pounds per square foot
MLHGR	Maximum linear heat generation ratio
MOC	middle of cycle
MOP	maintenance outline procedures
MOV	motor-operated valve
MOX	Mixed Oxide
MS	main steam
MSIP	Mechanical stress improvement process
MSIV	main steam isolation valve
MSIVA	MISV closure with all valves
MSIVC	MISV closure
MSIVF	MSIV closure with flux scram
MSIVO	MSIV closure with one valve
MSL	main steam line
MSLB	main steam line break

ACRONYM	**DEFINITION**
MSSS	main steam supply system
MVP	Mechanical vacuum pump
MWe	megawatts electric
MWt	megawatts thermal
N^{16}	Nitrogen ^{16}
n/cm2	neutrons per centimeter squared
NAI	Nuclear Applications, Inc.
NEI	Nuclear Energy Institute
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Corporation
NMCA	Noble metal chemical addition
NOS	normal overspeed
NPSH	net positive suction head
NRC	Nuclear Regulatory Commission
NRO	Office of New Reactors
NRR	NRC's Office of Nuclear Reactor Regulation
NSHC	no significant hazards consideration
NSSS	nuclear steam supply system
NUMARC	Nuclear Management and Resource Council, Inc.
O^{16}	Oxygen^{16}
O&M	Operation and Maintenance
OIG	Office of Inspector General
OLMCPR	operating limit minimum critical power ratio
OLTP	original licensed thermal power
OOS	out of service
OPRM	Oscillation Power Range Monitor
ORNL	Oak Ridge National Laboratory
OSP	offsite power

ACRONYM	DEFINITION
PATP	Power ascension and test plan
P-T	pressure-temperature
PCP	Primary condensate pumps
PCPL	Primary containment pressure limit
PCT	peak cladding temperature
pf	power factor
ppb	parts per billion
ppm	parts per million
PRA	Probabilistic Risk Assessment
PRDS	Pressure regulator downscale
PRFO	Pressure regulator failure to open
PSA	probabilistic safety assessment
PSB	Public Service Board
psi	pounds per square inch
psia	pounds per square inch absolute
psid	pounds per square inch differential
psig	pounds per square inch gauge
Pu	Plutonium
PUSAR	Power Uprate Safety Analysis Report
RACS	reactor auxiliaries cooling system
rad	radiation absorbed dose
RAI	request for additional information
RAW	risk achievement worth
RB	Reactor Building
RBM	rod block monitor
RBVS	Reactor Building Ventilation System
RCIC	reactor core isolation cooling
RCPB	reactor coolant pressure boundary

ACRONYM	DEFINITION
RCS	reactor coolant system
RES	NRC's Office of Nuclear Regulatory Research
RFC	Reliability *First* Corporation
RFO	refueling outage
RFP	reactor feedwater pump
RG	Regulatory Guide
RHR	residual heat removal
RIPD	reactor internal pressure difference
RLP	Reference Loading Pattern
RM	Radiation monitor
RMCS	reactor manual control system
RMS	root-mean-square
RPS	Reactor Protection System
RPT	recirculation pump trip
RPV	reactor pressure vessel
RR	reactor recirculation
RRCS	redundant reactivity control system
RRS	reactor recirculation system
RRU	reactor recirculation unit
RTP	rated thermal power
RV	Reactor Vessel
RVID	Reactor vessel integrity database
RWCS	reactor water cleanup system
RWCU	reactor water cleanup
RWE	rod withdraw error
RWM	rod worth minimizer
SACS	Safety Auxiliaries Cooling System
SAFDL	specified acceptable fuel design limits

ACRONYM	DEFINITION
SAGs	severe accident guidelines
SAMG	severe accident management guidelines
SBO	station blackout
SCC	stress-corrosion cracking
SCFH	standard cubic feet per hour
SCP	Secondary Condensate Pump
SDC	shutdown cooling
SDM	shutdown margin
SE	Safety Evaluation
SFP	spent fuel pool
SFPAVS	spent fuel pool area ventilation system
SFPCCS	spent fuel pool cooling and cleanup system
SFPCS	standby fuel pool cooling system
SGTS	standby gas treatment system
SIL	Services Information Letter
SL	safety limit
SLCS	standby liquid control system
SLMCPR	safety limit minimum critical power ratio
SLO	single loop operation
SLOCA	Small LOCA
SORV	stuck-open relief valve
SPC	suppression pool cooling
SPDS	safety parameter display system
SPV	South Plant Vent
SR	surveillance requirement
SRI	Slow recirculation increase
SRLR	Supplemental Reload Licensing Report
SRP	Standard Review Plan

ACRONYM	**DEFINITION**
SRV	safety relief valve
SSCs	structures, systems, and components
SSE	safe shutdown earthquake
SVELA	
SWS	service water system
T	thickness
TACS	Turbine auxiliaries cooling system
TAF	Top of active fuel
TAVS	turbine area ventilation system
TBS	Turbine bypass system
TCV	Turbine control valves
TEDE	total effective dose equivalent
TFSP	Turbine first stage pressure
TG	Turbine generator
TGSS	turbine gland sealing system
TIP	traversing incore probe
TOP	
TRC	Time reliability correlation
TRSV	Target Rock Solenoid Valves
TS	Technical Specification
TSBS	turbine steam bypass system
TSI	Turbine Supervisory Instrumentation
TSV	Turbine stop valve
TT	turbine trip
TTNBP	Turbine trip, no bypass
TTNBPF	Turbine trip, no bypass with flux scram
UFSAR	Updated Final Safety Analysis Report
UHS	ultimate heat sink

ACRONYM	DEFINITION
USE	upper shelf energy
UT	ultrasonic testing
UTL	upper tolerance limit
VF	void fraction
X/Qs	Atmosphere dispersion factors
ZD	zero dependency