UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

August 25, 2014

Mr. Michael J. Pacilio
President and Chief Nuclear Officer
Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: PEACH BOTTOM ATOMIC POWER STATION, UNITS 2 AND 3 - ISSUANCE OF AMENDMENTS RE: EXTENDED POWER UPRATE (TAC NOS. ME9631 AND ME9632)

Dear Mr. Pacilio:

The U.S. Nuclear Regulatory Commission (NRC) has issued the enclosed Amendment Nos. 293 and 296 to Renewed Facility Operating License Nos. DPR-44 and DPR-56 for Peach Bottom Atomic Power Station (PBAPS), Units 2 and 3. These amendments consist of changes to the Technical Specifications (TSs) and Facility Operating Licenses (FOLs) in response to your application dated September 28, 2012,[1] as supplemented by additional letters[2].

The amendments authorize an increase in the maximum licensed thermal power level for PBAPS, Units 2 and 3, from 3514 megawatts thermal (MWt) to 3951 MWt, which is an increase of approximately 12.4 percent. The NRC considers the requested increase in power level to be an extended power uprate (EPU).

Enclosure 4 transmitted herewith contains sensitive unclassified information When separated from Enclosure 4, this document is decontrolled.

1 Agencywide Documents Access and Management System (ADAMS) Accession No. ML122860201.

2 February 15, 2013 (ML13051A032), May 7, 2013 (ML13129A143), May 24, 2013 (ML13149A145), June 4, 2013 (ML13156A368), June 27, 2013 (ML13182A025), July 30, 2013 (ML13211A457), July 31, 2013 (ML13213A285), August 5, 2013 (ML13217A431), August 22, 2013 (ML13240A002), August 29, 2013 (ML13241A418), September 13, 2013 (ML13260A076), October 11, 2013 (ML13289A191), October 15, 2013 (ML13289A300), October 31, 2013 (ML13308A331), December 6, 2013 (ML13345A687), December 20, 2013 (ML13358A083), January 17, 2014 (ML14023A659), January 31, 2014 (ML14031A422), January 31, 2014 (ML14035A158), February 20, 2014 (ML14051A629), February 28, 2014 (ML14070A141), March 10, 2014 (ML14072A016), March 17, 2014 (ML14076A082), April 11, 2014 (ML14105A383), April 18, 2014 (ML14111A316), May 6, 2014 (ML14127A480), June 5, 2014 (ML14160A699), and June 20, 2014 (ML14171A409).

The NRC staff has determined that its safety evaluation (SE) for the subject amendments contains proprietary information pursuant to Title 10 of the *Code of Federal Regulations,* Section 2.390. Accordingly, the NRC staff has prepared a redacted, publicly available, non-proprietary version of the SE. Both versions of the SE are enclosed. Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,

RB Ennis

Richard B. Ennis, Senior Project Manager
Plant Licensing Branch I-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-277 and 50-278

Enclosures:
1. Amendment No. 293 to Renewed DPR-44
2. Amendment No. 296 to Renewed DPR-56
3. Non-Proprietary SE
4. Proprietary SE

cc w/encls 1, 2, and 3: Distribution via Listserv

Letter to M. Pacilio from R. Ennis dated August 25, 2014.

SUBJECT: PEACH BOTTOM ATOMIC POWER STATION, UNITS 2 AND 3 - ISSUANCE OF AMENDMENTS RE: EXTENDED POWER UPRATE (TAC NOS. ME9631 AND ME9632)

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

EXELON GENERATION COMPANY, LLC

PSEG NUCLEAR LLC

DOCKET NO. 50-277

PEACH BOTTOM ATOMIC POWER STATION, UNIT 2

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 293
Renewed License No. DPR-44

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Exelon Generation Company, LLC (Exelon Generation Company), and PSEG Nuclear LLC (the licensees), dated September 28, 2012, as supplemented by letters dated February 15, 2013, May 7, 2013, May 24, 2013, June 4, 2013, June 27, 2013, July 30, 2013, July 31, 2013, August 5, 2013, August 22, 2013, August 29, 2013, September 13, 2013, October 11, 2013, October 15, 2013, October 31, 2013, December 6, 2013, December 20, 2013, January 17, 2014, January 31, 2014 (two letters), February 20, 2014, February 28, 2014, March 10, 2014, March 17, 2014, April 11, 2014, April 18, 2014, May 6, 2014, June 5, 2014, and June 20, 2014, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraphs 2.C(1) and 2.C(2) of Renewed Facility Operating License No. DPR-44 are hereby amended to read as follows:

   (1) Maximum Power Level

   Exelon Generation Company is authorized to operate the Peach Bottom Atomic Power Station, Unit 2, at steady state reactor core power levels not in excess of 3951 megawatts thermal.

   (2) Technical Specifications

   The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 293, are hereby incorporated in the renewed license. Exelon Generation Company shall operate the facility in accordance with the Technical Specifications.

3. In addition, Renewed Facility Operating License No. DPR-44 is amended by the addition of new license condition 2.C(15), "Potential Adverse Flow Effects," as indicated in the attachment to this amendment.

4. This license amendment is effective as of its date of issuance and shall be implemented prior to startup from refueling outage P2R20.

FOR THE NUCLEAR REGULATORY COMMISSION

Daniel H. Dorman

Daniel H. Dorman, Acting Director
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Technical Specifications
and Facility Operating License

Date of Issuance: August 25, 2014

ATTACHMENT TO LICENSE AMENDMENT NO. 293

RENEWED FACILITY OPERATING LICENSE NO. DPR-44

DOCKET NO. 50-277

Replace the following pages of the Renewed Facility Operating License with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove	Insert
3	3
- - -	7b
- - -	7c
- - -	7d
- - -	7e
- - -	7f
- - -	7g

Replace the following pages of the Appendix A Technical Specifications with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove	Insert
1.1-5	1.1-5
2.0-1	2.0-1
3.1-21	3.1-21
3.1-22	3.1-22
3.1-23	3.1-23
3.1-24	3.1-24
3.1-25	3.1-25
3.2-1	3.2-1
3.2-2	3.2-2
3.2-4	3.2-4
3.3-2	3.3-2
3.3-3	3.3-3
3.3-3a	3.3-3a
3.3-6	3.3-6
3.3-6a	3.3-6a
3.3-7	3.3-7
3.3-8	3.3-8
3.3-22	3.3-22
3.3-31a	3.3-31a
3.3-31b	3.3-31b
3.3-31c	3.3-31c
3.3-41	3.3-41
3.3-52	3.3-52
3.4-7	3.4-7
3.4-8	3.4-8
3.4-9	3.4-9

Remove	Insert
3.5-5	3.5-5
3.5-11	3.5-11
3.6-16	3.6-16
3.6-28	3.6-28
3.6-30	3.6-30
3.6-30b	3.6-30b
3.7-1	3.7-1
3.7-2	3.7-2
3.7-12	3.7-12
3.8-25	3.8-25
3.8-27	3.8-27

(5) Exelon Generation Company, pursuant to the Act and 10 CFR Parts 30 and 70, to possess, but not to separate, such byproduct and special nuclear material as may be produced by operation of the facility, and such Class B and Class C low-level radioactive waste as may be produced by the operation of Limerick Generating Station, Units 1 and 2.

C. This renewed license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations in 10 CFR Chapter I: Part 20, Section 30.34 of Part 30, Section 40.41 of Part 40, Section 50.54 of Part 50, and Section 70.32 of Part 70; all applicable provisions of the Act and the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified below:

(1) Maximum Power Level

Exelon Generation Company is authorized to operate the Peach Bottom Atomic Power Station, Unit 2, at steady state reactor core power levels not in excess of 3951 megawatts thermal.

(2) Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 293, are hereby incorporated in the license. Exelon Generation Company shall operate the facility in accordance with the Technical Specifications.

(3) Physical Protection

Exelon Generation Company shall fully implement and maintain in effect all provisions of the Commission-approved physical security, training and qualification, and safeguards contingency plans including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions to 10 CFR 73.55 (51 FR 27817 and 27822), and the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The combined set of plans[1], submitted by letter dated May 17, 2006, is entitled: "Peach Bottom Atomic Power Station Security Plan, Training and Qualification Plan, Safeguards Contingency Plan, and Independent Spent Fuel Storage Installation Security Program, Revision 3." The set contains Safeguards Information protected under 10 CFR 73.21.

Exelon Generation Company shall fully implement and maintain in effect all provisions of the Commission-approved cyber security plan (CSP), including changes made pursuant to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The Exelon Generation Company CSP was approved by License Amendment No. 283.

(4) Fire Protection

The Exelon Generation Company shall implement and maintain in effect all provisions of the approved fire protection program as described in the Updated Final Safety Analysis Report for the facility, and as approved in the NRC Safety Evaluation Report (SER) dated May 23, 1979, and Supplements dated August 14, September 15, October 10 and November 24, 1980, and in the NRC SERs dated September 16, 1993, and August 24, 1994, subject to the following provision:

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[1] The Training and Qualification Plan and Safeguards Contingency Plan are Appendices to the Security Plan.

(15) Potential Adverse Flow Effects

In conjunction with the license amendment to revise paragraph 2.C(1) of Renewed Facility Operating License No. DPR-44, for Peach Bottom Unit 2, to reflect the new maximum licensed reactor core power level of 3951 megawatts thermal (MWt), the license is also amended to add the following license condition. 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). This license condition is applicable to the initial power ascension from 3514 MWt to the extended power uprate (EPU) power level of 3951 MWt:

(a) The following requirements are placed on the initial operation of the facility, above the thermal power level of 3514 MWt, for the power ascension to 3951 MWt. These conditions are applicable until the first time full EPU conditions (3951 MWt) are achieved. If the number of active main steam line (MSL) strain gauges is less than two strain gauges (180 degrees apart) at any of the eight MSL locations, Exelon Generation Company will stop power ascension and repair/replace the damaged strain gauges and only then resume power ascension. In addition, sufficient on-dryer strain gauges must remain in working order to monitor all dryer peak stress locations with a minimum alternating stress ratio (MASR) less than 1.5. In the event there are no working on-dryer strain gauges, with coherence of greater than 0.5 with any peak stress location, Exelon Generation Company will: (1) stop power ascension; (2) evaluate the dryer MASR at the current power level and at the projected EPU power level; and (3) provide the results to the NRC Project Manager via e-mail. Exelon Generation Company shall not resume power ascension for at least 24 hours after the NRC Project Manager confirms receipt of the MASR results unless, prior to the expiration of the 24 hour period, the NRC Project Manager advises that the NRC staff has no objections to the continuation of power ascension. Furthermore, power ascension may only resume if Exelon Generation Company determines that the dryer MASR will remain greater than 1.0.

1. Exelon Generation Company shall provide a brief stress summary report for the replacement steam dryer (RSD) based on MSL strain gauge and on-dryer instrument data collected at or near 3514 MWt for NRC review before increasing power above 3514 MWt. Exelon Generation Company shall also provide a brief vibration summary report for piping and valve vibration data collected at or near 3514 MWt for NRC review before increasing power above 3514 MWt. Both summary reports shall be provided by e-mail to the NRC Project

Manager. Exelon Generation Company shall not increase power above 3514 MWt for at least 240 hours after the NRC Project Manager confirms receipt of the reports unless, prior to expiration of the 240 hour period, the NRC Project Manager advises that the NRC staff has no objections to the continuation of power ascension. The stress summary report shall include the information in items a through f, and the vibration summary report shall include the information in items g through i, as follows:

a. A comparison of predicted and measured pressure spectra plots on the RSD.

b. A comparison of predicted and measured root mean square (RMS) strains and spectra plots on the RSD.

c. End-to-end bias errors and uncertainties (B/Us) for RSD strains, along with a demonstration that the application of these B/Us leads to RSD strain simulations that bound the measured spectra at dominant frequencies and RMS strains at all active strain gauge locations.

d. RSD strain gauge limits based on benchmarking performed near 3514 MWt. This will include the predicted RSD strains at each measured location and the corresponding updated MASR near 3514 MWt.

e. Predicted (extrapolated) strains at the active RSD strain gauge locations at 104% of 3514 MWt and an evaluation against acceptance limits.

f. Predicted RSD stresses and MASRs at EPU.

g. Vibration data for piping and valve locations deemed prone to vibration and vibration monitoring locations identified in Attachment 13 to the EPU application dated September 28, 2012, and Supplement 16 dated December 20, 2013, including the following locations: MSLs (including those in the drywell, turbine building and in the steam tunnel), Feedwater Lines (including those in the drywell and turbine building), Safety Relief Valves (SRVs) and Main Steam Isolation Valves in the drywell.

h. An evaluation of the measured vibration data collected in item 1.g above compared against acceptance limits.

i. Predicted vibration values and associated acceptance limits at approximately 104 percent, 108 percent, and 112.4 percent of 3514 MWt using the data collected in item 1.g above.

2. Exelon Generation Company shall monitor the RSD strain gauges during power ascension above 3514 MWt for increasing strain fluctuations. Upon the initial increase of power above 3514 MWt until reaching 3951 MWt, Exelon Generation Company shall collect data from the RSD strain gauges at nominal 2 percent thermal power increments and evaluate steam dryer stress ratios based on these data. Summaries of the results shall be provided via e-mail to the NRC Project Manager at approximately 104 percent and 108 percent of 3514 MWt.

3. Exelon Generation Company shall monitor the MSL strain gauges during power ascension above 3514 MWt for increasing pressure fluctuations in the main steam lines. Upon the initial increase of power above 3514 MWt until reaching 3951 MWt, Exelon Generation Company shall collect data from the MSL strain gauges and on-dryer instruments at nominal 2 percent thermal power increments.

4. Exelon Generation Company shall hold the facility at approximately 104 percent and 108 percent of 3514 MWt to perform the following:

   a. Collect strain data from the MSL strain gauges and collect data from on-dryer instruments (accelerometers, strain gauges, and pressure transducers).

   b. Collect vibration data for the locations included in the vibration summary report discussed above.

   c. Evaluate steam dryer performance based on RSD strain gauge data.

   d. Evaluate the measured vibration data (collected in item 4.b above) at that power level, data projected to EPU conditions, trends, and comparison with the acceptance limits.

   e. Provide the steam dryer evaluation and the vibration evaluation, including the data collected, via e-mail to the NRC Project Manager, upon completion of the evaluation for each of the two hold points.

f. Exelon Generation Company shall submit a comparison of predicted and measured pressures and strains (RMS and spectra) on the RSD at 104% of 3514 MWt and 108% of 3514 MWt during power ascension.

g. Exelon Generation Company shall not increase power above each hold point until 96 hours after the NRC Project Manager confirms receipt of the evaluations unless, prior to the expiration of the 96 hour period, the NRC Project Manager advises that the NRC staff has no objections to the continuation of power ascension.

5. If any RMS level measured by the active RSD strain gauges exceeds allowable Level 1 limits, Exelon Generation Company shall return the facility to a power level at which the limit(s) is not exceeded. Exelon Generation Company shall resolve the discrepancy, evaluate and document the continued structural integrity of the steam dryer, and provide that documentation to the NRC Project Manager via e-mail prior to further increases in reactor power. If a revised stress analysis is performed and new RSD strain limits are developed, then Exelon Generation Company shall not further increase power above each hold point until 96 hours after the NRC Project Manager confirms receipt of the documentation or until the NRC Project Manager advises that the NRC staff has no objections to the continuation of power ascension, whichever comes first. Additional detail is provided in paragraph (b)1 below.

(b) Exelon Generation Company shall implement the following actions for the initial power ascension from 3514 MWt to 3951 MWt condition:

1. In the event that RMS strain levels for active RSD strain gauges are identified to exceed the allowable Level 1 limits during power ascension above 3514 MWt, Exelon Generation Company shall re-evaluate dryer loads and stresses, and re-establish updated MASRs and RSD strain gauge RMS limits. In the event that stress analyses are re-performed based on new strain gauge data to address paragraph (a)5 above, the revised load definition, stress analysis, and limits shall include:

   a. Determination of end-to-end B/Us and their application in determining maximum alternating stress intensities.

   b. Use of bump-up factors associated with all of the SRV acoustic resonances, as determined from the scale model test results or in-plant data acquired during power ascension.

2. After reaching 3951 MWt, Exelon Generation Company shall obtain measurements from the MSL strain gauges and establish the steam dryer flow-induced vibration load fatigue margin for the facility, update the dryer stress report, and re-establish the RSD strain gauge limits based on the updated load definition. These data will be provided to the NRC staff as described below in paragraph (e).

(c) Exelon Generation Company shall prepare the EPU power ascension test procedure to include:

1. The stress limits and the corresponding RSD strain limits to be applied for evaluating steam dryer performance.

2. Specific hold points and their durations during EPU power ascension.

3. Activities to be accomplished during the hold points.

4. Plant parameters to be monitored.

5. Inspections and walkdowns to be conducted for steam, feedwater, and condensate systems and components during the hold points.

6. Methods to be used to trend plant parameters.

7. Acceptance criteria for monitoring and trending plant parameters, and conducting the walkdowns and inspections.

8. Actions to be taken if acceptance criteria are not satisfied.

9. Verification of the completion of commitments and planned actions specified in the 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 3514 MWt. Exelon Generation Company shall provide the related EPU startup test procedure sections to the NRC Project Manager via e-mail prior to increasing power above 3514 MWt.

(d) 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:

1. During initial power ascension testing above 3514 MWt, each of the two hold points shall be at increments of 4 percent of 3514 MWt.

2. Level 1 performance criteria.

3. The methodology for establishing the RSD strain limits used for the Level 1 and Level 2 performance.

(e) 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 in accordance with 10 CFR 50.4. The report shall include a final load definition and stress report of the steam dryer, including the results of a complete re-analysis using the end-to-end B/Us determined at EPU conditions and a comparison of predicted and measured pressures and strains (RMS levels and spectra) on the RSD. The report shall be submitted within 90 days of the completion of EPU power ascension testing for Peach Bottom Unit 2.

(f) During the first two scheduled refueling outages after reaching EPU conditions, a visual inspection shall be conducted of the steam dryer as described in the inspection guidelines contained in WCAP-17635-P.

(g) The results of the visual inspections of the steam dryer shall be submitted to the NRC staff in a report in accordance with 10 CFR 50.4. The report shall be submitted within 90 days following startup from each of the first two respective refueling outages.

(h) Within 6 months following completion of the second refueling outage, after the implementation of the EPU, the licensee shall submit a long-term steam dryer inspection plan based on industry operating experience along with the baseline inspection results.

The license condition described above shall expire: (1) upon satisfaction of the requirements in paragraphs (f) and (g), provided that a visual inspection of the steam dryer does not reveal any new unacceptable flaw(s) or unacceptable flaw growth that is due to fatigue, and; (2) upon satisfaction of the requirements specified in paragraph (h).

1.1 Definitions

PHYSICS TESTS (continued)	b. Authorized under the provisions of 10 CFR 50.59; or c. Otherwise approved by the Nuclear Regulatory Commission.
PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)	The PTLR is the unit-specific document that provides the reactor vessel pressure and temperature limits, including heatup and cooldown rates, for the current reactor vessel fluence period. These pressure and temperature limits shall be determined for each fluence period in accordance with Specification 5.6.7.
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of 3951 MWt.
REACTOR PROTECTION SYSTEM (RPS) RESPONSE TIME	The RPS RESPONSE TIME shall be that time interval from the opening of the sensor contact up to and including the opening of the trip actuator contacts.
RECENTLY IRRADIATED FUEL	RECENTLY IRRADIATED FUEL is fuel that has occupied part of a critical reactor core within the previous 24 hours. When using this definition to suspend the Applicability of LCOs, secondary containment ground-level hatches H15, H16, H17, H18, H19, and H33 shall be closed during the movement of any irradiated fuel in Secondary Containment.
SHUTDOWN MARGIN (SDM)	SDM shall be the amount of reactivity by which the reactor is subcritical or would be subcritical assuming that: a. The reactor is xenon free; b. The moderator temperature is 68°F; and c. All control rods are fully inserted except for the single control rod of highest reactivity worth, which is assumed to be fully withdrawn. With control rods not capable of being fully inserted, the reactivity worth of these control rods must be accounted for in the determination of SDM.

(continued)

2.0 SAFETY LIMITS (SLs)

2.1 SLs

2.1.1 Reactor Core SLs

2.1.1.1 With the reactor steam dome pressure < 785 psig or core flow < 10% rated core flow:

THERMAL POWER shall be ≤ 23% RTP.

2.1.1.2 With the reactor steam dome pressure ≥ 785 psig and core flow ≥ 10% rated core flow:

MCPR shall be ≥ 1.10 for two recirculation loop operation or ≥ 1.14 for single recirculation loop operation.

2.1.1.3 Reactor vessel water level shall be greater than the top of active irradiated fuel.

2.1.2 Reactor Coolant System Pressure SL

Reactor steam dome pressure shall be ≤ 1325 psig.

2.2 SL Violations

With any SL violation, the following actions shall be completed within 2 hours:

2.2.1 Restore compliance with all SLs; and

2.2.2 Insert all insertable control rods.

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. Two SLC subsystems inoperable for reasons other than Condition A.	C.1	Restore one SLC subsystem to OPERABLE status.	8 hours
D. Required Action and associated Completion Time not met.	D.1	Be in MODE 3.	12 hours
	AND		
	D.2	Be in MODE 4.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.7.1	Verify level of sodium pentaborate solution in the SLC tank is ≥ 52%.	In accordance with the Surveillance Frequency Control Program.
SR 3.1.7.2	Verify temperature of sodium pentaborate solution is ≥ 53°F.	In accordance with the Surveillance Frequency Control Program.
SR 3.1.7.3	Verify temperature of pump suction piping is ≥ 53°F.	In accordance with the Surveillance Frequency Control Program.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.1.7.4	Verify continuity of explosive charge.	In accordance with the Surveillance Frequency Control Program.
SR 3.1.7.5	Verify the concentration of boron in solution is ≥ 8.32% weight and ≤ 9.82% weight.	In accordance with the Surveillance Frequency Control Program. AND Once within 24 hours after water or boron is added to solution AND Once within 24 hours after solution temperature is restored within limits
SR 3.1.7.6	Verify each SLC subsystem manual and power operated valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position, or can be aligned to the correct position.	In accordance with the Surveillance Frequency Control Program.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.1.7.7	Deleted	
SR 3.1.7.8	Verify each pump develops a flow rate ≥ 49.1 gpm at a discharge pressure ≥ 1275 psig.	In accordance with the Inservice Testing Program
SR 3.1.7.9	Verify flow through one SLC subsystem from pump into reactor pressure vessel.	In accordance with the Surveillance Frequency Control Program.
SR 3.1.7.10	Verify sodium pentaborate enrichment is ≥ 92.0 atom percent B-10.	In accordance with the Surveillance Frequency Control Program. <u>AND</u> Once within 8 hours after addition to SLC tank.

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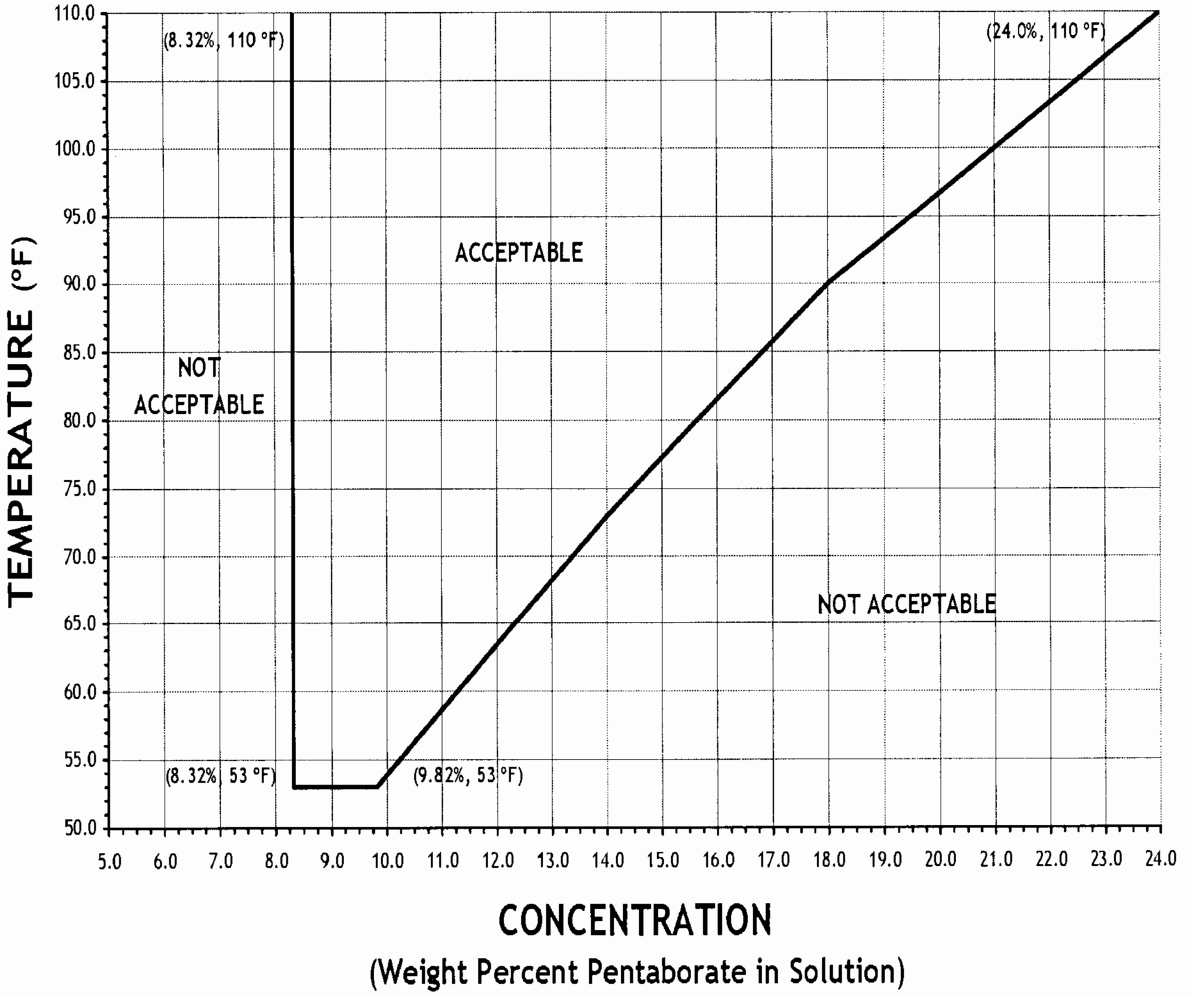

Figure 3.1.7-1 (page 1 of 1)
Sodium Pentaborate Solution Temperature Versus Concentration Requirements

3.2 POWER DISTRIBUTION LIMITS

3.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)

LCO 3.2.1 All APLHGRs shall be less than or equal to the limits specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ 23% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Any APLHGR not within limits.	A.1 Restore APLHGR(s) to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 23% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.2.1.1 Verify all APLHGRs are less than or equal to the limits specified in the COLR.	Once within 12 hours after ≥ 23% RTP <u>AND</u> In accordance with the Surveillance Frequency Control Program.

3.2 POWER DISTRIBUTION LIMITS

3.2.2 MINIMUM CRITICAL POWER RATIO (MCPR)

LCO 3.2.2 All MCPRs shall be greater than or equal to the MCPR operating limits specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ 23% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Any MCPR not within limits.	A.1 Restore MCPR(s) to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 23% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.2.2.1 Verify all MCPRs are greater than or equal to the limits specified in the COLR.	Once within 12 hours after ≥ 23% RTP <u>AND</u> In accordance with the Surveillance Frequency Control Program.

(continued)

3.2 POWER DISTRIBUTION LIMITS

3.2.3 LINEAR HEAT GENERATION RATE (LHGR)

LCO 3.2.3 All LHGRs shall be less than or equal to the limits specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ 23% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Any LHGR not within limits.	A.1 Restore LHGR(s) to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 23% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.2.3.1 Verify all LHGRs are less than or equal to the limits specified in the COLR.	Once within 12 hours after ≥ 23% RTP AND In accordance with the Surveillance Frequency Control Program.

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One or more automatic Functions with RPS trip capability not maintained. OR Two or more manual Functions with RPS trip capability not maintained.	C.1	Restore RPS trip capability.	1 hour
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1	Enter the Condition referenced in Table 3.3.1.1-1 for the channel.	Immediately
E. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	E.1	Reduce THERMAL POWER to < 26.7% RTP.	4 hours
F. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	F.1	Be in MODE 2.	6 hours
G. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	G.1	Be in MODE 3.	12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
H. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	H.1	Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately
I. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	I.1	Initiate alternate method to detect and suppress thermal hydraulic instability oscillations.	12 hours
	AND		
	I.2	--------NOTE-------- LCO 3.0.4 is not applicable. -------------------- Restore required channels to OPERABLE.	120 days
J. Required Action and associated Completion Time of Condition I not met.	J.1	Reduce THERMAL POWER to < 23% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

------------------------------------NOTES------------------------------------

1. Refer to Table 3.3.1.1-1 to determine which SRs apply for each RPS Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains RPS trip capability.

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.1.2	------------------NOTE------------------ Not required to be performed until 12 hours after THERMAL POWER ≥ 23% RTP. -- Verify the absolute difference between the average power range monitor (APRM) channels and the calculated power is ≤ 2% RTP while operating at ≥ 23% RTP.	In accordance with the Surveillance Frequency Control Program.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.12	-------------------NOTES------------------- 1. Neutron detectors are excluded. 2. For Function 1, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. 3. For Functions 2.b and 2.f, the recirculation flow transmitters that feed the APRMs are included. --- Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.1.13	Verify Turbine Stop Valve—Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Functions are not bypassed when THERMAL POWER is ≥ 26.7% RTP.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.1.14	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.1.15	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.16	Calibrate each radiation detector.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.1.17	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.1.18	Verify the RPS RESPONSE TIME is within limits.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.1.19	Verify OPRM is not bypassed when APRM Simulated Thermal Power is ≥ 26.2% and recirculation drive flow is <60%.	In accordance with the Surveillance Frequency Control Program.

Table 3.3.1.1-1 (page 1 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Wide Range Neutron Monitors					
a. Period-Short	2	3	G	SR 3.3.1.1.1 SR 3.3.1.1.5 SR 3.3.1.1.12 SR 3.3.1.1.17 SR 3.3.1.1.18	≥ 13 seconds
	5(a)	3	H	SR 3.3.1.1.1 SR 3.3.1.1.6 SR 3.3.1.1.12 SR 3.3.1.1.17 SR 3.3.1.1.18	≥ 13 seconds
b. Inop	2	3	G	SR 3.3.1.1.5 SR 3.3.1.1.17	NA
	5(a)	3	H	SR 3.3.1.1.6 SR 3.3.1.1.17	NA
2. Average Power Range Monitors					
a. Neutron Flux-High (Setdown)	2	3(c)	G	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.11 SR 3.3.1.1.12	≤ 15.0% RTP
b. Simulated Thermal Power-High	1	3(c)	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.8 SR 3.3.1.1.11 SR 3.3.1.1.12(e),(f)	≤ 0.55 W + 63.3% RTP(b) and ≤ 118.0% RTP
c. Neutron Flux-High	1	3(c)	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.8 SR 3.3.1.1.11 SR 3.3.1.1.12	≤ 119.7% RTP
d. Inop	1,2	3(c)	G	SR 3.3.1.1.11	NA
e. 2-Out-Of-4 Voter	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.11 SR 3.3.1.1.17 SR 3.3.1.1.18	NA
f. OPRM Upscale	≥ 23% RTP	3(c)	I	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.11 SR 3.3.1.1.12 SR 3.3.1.1.19	(d)

(continued)

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

(b) 0.55 (W - ΔW) + 61.5% RTP when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating."

(c) Each APRM channel provides inputs to both trip systems.

(d) See COLR for OPRM period based detection algorithm (PBDA) setpoint limits.

(e) If the as-found channel setpoint is outside its predefined as-found tolerance, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.

(f) The instrument channel set point shall be reset to a value that is within the Leave Alone Zone (LAZ) around the Nominal Trip Setpoint (NTSP) at the completion of the surveillance; otherwise, the channel shall be declared inoperable. Setpoints more conservative than the NTSP are acceptable provided the as-found tolerance and LAZ apply to the actual setpoint implemented in the Surveillance procedures to confirm channel performance. The NTSP methodologies used to determine the as-found tolerance and the LAZ are specified in the Bases associated with the specified function.

Table 3.3.1.1-1 (page 2 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
3. Reactor Pressure —High	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.9 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 1085.0 psig
4. Reactor Vessel Water Level—Low (Level 3)	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.9 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≥ 1.0 inches
5. Main Steam Isolation Valve —Closure	1	8	F	SR 3.3.1.1.9 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 10% closed
6. Drywell Pressure — High	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.9 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 2.0 psig
7. Scram Discharge Volume Water Level —High	1,2	2	G	SR 3.3.1.1.9 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 50.0 gallons
	5[(a)]	2	H	SR 3.3.1.1.9 SR 3.3.1.1.15 SR 3.3.1.1.17	≤ 50.0 gallons
8. Turbine Stop Valve—Closure	≥ 26.7% RTP	4	E	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 10% closed
9. Turbine Control Valve Fast Closure, Trip Oil Pressure—Low	≥ 26.7% RTP	2	E	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≥ 500.0 psig
10. Turbine Condenser —Low Vacuum	1	2	F	SR 3.3.1.1.1 SR 3.3.1.1.9 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≥ 23.0 inches Hg vacuum
11. Main Steam Line —High Radiation	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.10 SR 3.3.1.1.16 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 15 X Full Power Background
12. Reactor Mode Switch — Shutdown Position	1,2	1	G	SR 3.3.1.1.14 SR 3.3.1.1.17	NA
	5[(a)]	1	H	SR 3.3.1.1.14 SR 3.3.1.1.17	NA

(continued)

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

3.3 INSTRUMENTATION

3.3.2.2 Feedwater and Main Turbine High Water Level Trip Instrumentation

LCO 3.3.2.2 Two channels per trip system of the Digital Feedwater Control System (DFCS) high water level trip instrumentation Function shall be OPERABLE.

APPLICABILITY: THERMAL POWER ≥ 23% RTP.

ACTIONS

------------------------------------NOTE------------------------------------
Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more DFCS high water level trip channels inoperable.	A.1	Place channel in trip.	72 hours
B. DFCS high water level trip capability not maintained.	B.1	Restore DFCS high water level trip capability.	2 hours
C. Required Action and associated Completion Time not met.	C.1	--------NOTE-------- Only applicable if inoperable channel is the result of inoperable feedwater pump turbine or main turbine stop valve. --------------------	
		Remove affected feedwater pump(s) and main turbine valve(s) from service.	4 hours
	OR		
	C.2	Reduce THERMAL POWER to < 23% RTP.	4 hours

3.3 INSTRUMENTATION

3.3.4.2 End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation

LCO 3.3.4.2

a. Two channels per trip system for each EOC-RPT instrumentation Function listed below shall be OPERABLE:

1. Turbine Stop Valve (TSV)—Closure; and
2. Turbine Control Valve (TCV) Fast Closure, Trip Oil Pressure—Low.

OR

b. The following limits are made applicable:

1. LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," limits for inoperable EOC-RPT as specified in the COLR;
2. LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," limits for inoperable EOC-RPT as specified in the COLR; and
3. LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)," limits for inoperable EOC-RPT as specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ 26.7% RTP.

ACTIONS

------------------------------------NOTE------------------------------------
Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 Restore channel to OPERABLE status. OR A.2 --------NOTE--------- Not applicable if inoperable channel is the result of an inoperable breaker. --------------------- Place channel in trip.	72 hours 72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One or more Functions with EOC-RPT trip capability not maintained.	B.1	Restore EOC-RPT trip capability.	2 hours
C. Required Action and associated Completion Time not met.	C.1	---------NOTE-------- Only applicable if inoperable channel is the result of an inoperable RPT breaker. -------------------- Remove the affected recirculation pump from service.	 4 hours
	OR		
	C.2	Reduce THERMAL POWER to < 26.7% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

------------------------------------NOTE------------------------------------
When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains EOC-RPT trip capability.

SURVEILLANCE		FREQUENCY
SR 3.3.4.2.1	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.4.2.2	Perform CHANNEL CALIBRATION. The Allowable Values shall be: TSV—Closure: ≤ 10% closed; and TCV Fast Closure, Trip Oil Pressure—Low: ≥ 500 psig.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.4.2.3	Perform LOGIC SYSTEM FUNCTIONAL TEST including breaker actuation.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.4.2.4	Verify TSV—Closure and TCV Fast Closure, Trip Oil Pressure—Low Functions are not bypassed when THERMAL POWER is ≥ 26.7% RTP.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.4.2.5	-----------------NOTE----------------- Breaker interruption time may be assumed from the most recent performance of SR 3.3.4.2.6. --------------------------------------- Verify the EOC-RPT SYSTEM RESPONSE TIME is within limits.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.4.2.6	Determine RPT breaker interruption time.	In accordance with the Surveillance Frequency Control Program.

Table 3.3.5.1-1 (page 3 of 5)
Emergency Core Cooling System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
3. High Pressure Coolant Injection (HPCI) System					
a. Reactor Vessel Water Level —Low Low (Level 2)	1, 2(d), 3(d)	4	B	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ -48.0 inches
b. Drywell Pressure —High	1, 2(d), 3(d)	4	B	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≤ 2.0 psig
c. Reactor Vessel Water Level —High (Level 8)	1, 2(d), 3(d)	2	C	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≤ 46.0 inches
d. Condensate Storage Tank Level —Low	1, 2(d), 3(d)	2	D	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ 5.25 ft above tank bottom
e. Suppression Pool Water Level —High	1, 2(d), 3(d)	2	D	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≤ 16 ft 7 inches
f. High Pressure Coolant Injection Pump Discharge Flow —Low (Bypass)	1, 2(d), 3(d)	1	E	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ 3.5 in-wc and ≤ 19.0 in-wc
4. Automatic Depressurization System (ADS) Trip System A					
a. Reactor Vessel Water Level —Low Low Low (Level 1)	1, 2(e), 3(e)	2	F	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ -160.0 inches
b. Drywell Pressure —High	1, 2(e), 3(e)	2	F	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≤ 2.0 psig
c. Automatic Depressurization System Initiation Timer	1, 2(e), 3(e)	1	G	SR 3.3.5.1.4 SR 3.3.5.1.5	≤ 115.0 seconds

(continued)

(d) With reactor steam dome pressure > 150 psig.

(e) With reactor steam dome pressure > 100 psig.

Table 3.3.6.1-1 (page 1 of 3)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Main Steam Line Isolation					
a. Reactor Vessel Water Level – Low Low Low (Level 1)	1,2,3	2	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.7	≥ -160.0 inches
b. Main Steam Line Pressure – Low	1	2	E	SR 3.3.6.1.3 SR 3.3.6.1.7	≥ 825.0 psig
c. Main Steam Line Flow – High	1,2,3	2 per MSL	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.7	≤ 173.8 psid
d. Main Steam Line – High Radiation	1,2,3	2	D	SR 3.3.6.1.1 SR 3.3.6.1.3 SR 3.3.6.1.6 SR 3.3.6.1.7	≤ 15 X Full Power Background
e. Turbine Building Main Steam Tunnel Temperature – High	1,2,3	6	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.7	≤ 200.0°F
f. Reactor Building Main Steam Tunnel Temperature-High	1,2,3	2	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.7	≤ 230.0°F
2. Primary Containment Isolation					
a. Reactor Vessel Water Level – Low (Level 3)	1,2,3	2	G	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.7	≥ 1.0 inches
b. Drywell Pressure – High	1,2,3	2	G	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.7	≤ 2.0 psig
c. Main Stack Monitor Radiation – High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.7	≤ 2 X 10^{-2} μCi/cc
d. Reactor Building Ventilation Exhaust Radiation – High	1,2,3	2	G	SR 3.3.6.1.1 SR 3.3.6.1.3 SR 3.3.6.1.7	≤ 16.0 mR/hr
e. Refueling Floor Ventilation Exhaust Radiation – High	1,2,3	2	G	SR 3.3.6.1.1 SR 3.3.6.1.3 SR 3.3.6.1.7	≤ 16.0 mR/hr

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.2.1	-------------------NOTES------------------- 1. Not required to be performed until 4 hours after associated recirculation loop is in operation. 2. Not required to be performed until 24 hours after > 23% RTP. --- Verify at least one of the following criteria (a, b, or c) is satisfied for each operating recirculation loop: a. Recirculation pump flow to speed ratio differs by ≤ 5% from established patterns, and jet pump loop flow to recirculation pump speed ratio differs by ≤ 5% from established patterns. b. Each jet pump diffuser to lower plenum differential pressure differs by ≤ 20% from established patterns. c. Each jet pump flow differs by ≤ 10% from established patterns.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.3 Safety Relief Valves (SRVs) and Safety Valves (SVs)

LCO 3.4.3 The safety function of 13 valves (any combination of SRVs and SVs) shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required SRVs or SVs inoperable.	A.1 Be in MODE 3. AND A.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.3.1	Verify the safety function lift setpoints of the required SRVs and SVs are as follows: Number of SRVs — Setpoint (psig) 4 — 1135 ± 34.1 4 — 1145 ± 34.4 3 — 1155 ± 34.7 Number of SVs — Setpoint (psig) 3 — 1260 ± 37.8 Following testing, lift settings shall be within ± 1%.	In accordance with the Inservice Testing Program
SR 3.4.3.2	Verify each required SRV actuator strokes when manually actuated in the depressurization mode.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.1.5	------------------NOTE------------------ Not required to be performed if performed within the previous 31 days. -- Verify each recirculation pump discharge valve cycles through one complete cycle of full travel or is de-energized in the closed position.	 Once each startup prior to exceeding 23% RTP
SR 3.5.1.6	Verify automatic transfer of the power supply from the normal source to the alternate source for each LPCI subsystem inboard injection valve and each recirculation pump discharge valve.	In accordance with the Surveillance Frequency Control Program.
SR 3.5.1.7	------------------NOTE------------------ For the core spray pumps, SR 3.5.1.7 may be met using equivalent values for flow rate and test pressure determined using pump curves. -- Verify the following ECCS pumps develop the specified flow rate against a system head corresponding to the specified reactor pressure. SYSTEM / FLOW RATE / NO. OF PUMPS / SYSTEM HEAD CORRESPONDING TO A REACTOR PRESSURE OF Core Spray / ≥ 3,125 gpm / 1 / ≥ 105 psig LPCI / ≥ 8,600 gpm / 1 / ≥ 20 psig	 In accordance with the Surveillance Frequency Control Program.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.5.2.5	-------------------NOTE------------------- For the CS pumps, SR 3.5.2.5 may be met using equivalent values for flow rate and test pressure determined using pump curves. -- Verify each required ECCS pump develops the specified flow rate against a system head corresponding to the specified reactor pressure. SYSTEM / FLOW RATE / NO. OF PUMPS / SYSTEM HEAD CORRESPONDING TO A REACTOR PRESSURE OF CS / ≥ 3,125 gpm / 1 / ≥ 105 psig LPCI / ≥ 8,600 gpm / 1 / ≥ 20 psig	In accordance with the Surveillance Frequency Control Program.
SR 3.5.2.6	-------------------NOTE------------------- Vessel injection/spray may be excluded. -- Verify each required ECCS injection/spray subsystem actuates on an actual or simulated automatic initiation signal.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.1.3.14	Verify combined MSIV leakage rate for all four main steam lines is ≤ 170 scfh, and ≤ 85 scfh for any one steam line, when tested at ≥ 25 psig.	In accordance with the Primary Containment Leakage Rate Testing Program
SR 3.6.1.3.15	Verify each 6 inch and 18 inch primary containment purge valve and each 18 inch primary containment exhaust valve is blocked to restrict opening greater than the required maximum opening angle.	In accordance with the Surveillance Frequency Control Program.
SR 3.6.1.3.16	Replace the inflatable seal of each 6 inch and 18 inch primary containment purge valve and each 18 inch primary containment exhaust valve.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.3.1	Verify each RHR suppression pool cooling subsystem manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position or can be aligned to the correct position.	In accordance with the Surveillance Frequency Control Program.
SR 3.6.2.3.2	Verify each required RHR pump develops a flow rate $\geq$ 8,600 gpm through the associated heat exchanger while operating in the suppression pool cooling mode.	In accordance with the Inservice Testing Program
SR 3.6.2.3.3	Verify manual transfer capability of power supply for the RHR motor-operated flow control valve and the RHR cross-tie motor-operated valve from the normal source to the alternate source.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.4.1	Verify each RHR suppression pool spray subsystem manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position or can be aligned to the correct position.	In accordance with the Surveillance Frequency Control Program.
SR 3.6.2.4.2	Verify each suppression pool spray nozzle is unobstructed.	In accordance with the Surveillance Frequency Control Program.
SR 3.6.2.4.3	Verify manual transfer capability of power supply for the RHR motor-operated flow control valve and the RHR cross-tie motor-operated valve from the normal source to the alternate source.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.5.1	Verify each RHR drywell spray subsystem manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position or can be aligned to the correct position.	In accordance with the Surveillance Frequency Control Program.
SR 3.6.2.5.2	Verify each drywell spray nozzle is unobstructed.	In accordance with the Surveillance Frequency Control Program.
SR 3.6.2.5.3	Verify manual transfer capability of power supply for the RHR motor-operated flow control valve and the RHR cross-tie motor-operated valve from the normal source to the alternate source.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.1 High Pressure Service Water (HPSW) System

LCO 3.7.1 Two HPSW subsystems and the HPSW cross tie shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One HPSW subsystem inoperable.	-----------NOTE------------- Enter applicable Conditions and Required Actions of LCO 3.4.7, "Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown," for RHR shutdown cooling made inoperable by HPSW System. ----------------------------	
	A.1 Restore HPSW subsystem to OPERABLE status.	7 days
B. HPSW cross tie inoperable.	B.1 Restore HPSW cross tie to OPERABLE status.	7 days
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Be in MODE 3.	12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Both HPSW subsystems inoperable.	-----------NOTE------------- Enter applicable Conditions and Required Actions of LCO 3.4.7 for RHR shutdown cooling made inoperable by HPSW System. ----------------------------	
	D.1 Restore one HPSW subsystem to OPERABLE status.	8 hours
E. Required Action and associated Completion Time of Condition D not met.	E.1 Be in MODE 3.	12 hours
	<u>AND</u>	
	E.2 Be in MODE 4.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.1.1	Verify each HPSW manual and power operated valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position or can be aligned to the correct position.	In accordance with the Surveillance Frequency Control Program.
SR 3.7.1.2	Verify manual transfer capability of power supply for the HPSW cross-tie motor-operated valve and the RHR heat exchanger HPSW outlet valve from the normal source to the alternate source.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.6 Main Turbine Bypass System

LCO 3.7.6 The Main Turbine Bypass System shall be OPERABLE.

<u>OR</u>

The following limits are made applicable:

a. LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," limits for an inoperable Main Turbine Bypass System, as specified in the COLR;

b. LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," limits for an inoperable Main Turbine Bypass System, as specified in the COLR; and

c. LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)," limits for an inoperable Main Turbine Bypass System, as specified in the COLR.

APPLICABILITY: THERMAL POWER $\geq$ 23% RTP.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Requirements of the LCO not met.	A.1	Satisfy the requirements of the LCO.	2 hours
B. Required Action and associated Completion Time not met.	B.1	Reduce THERMAL POWER to < 23% RTP.	4 hours

3.8 ELECTRICAL POWER SYSTEMS

3.8.3 Diesel Fuel Oil, Lube Oil, and Starting Air

LCO 3.8.3 The stored diesel fuel oil, lube oil, and starting air subsystem shall be within limits for each required diesel generator (DG).

APPLICABILITY: When associated DG is required to be OPERABLE.

ACTIONS

-------------------------------------NOTE-------------------------------------
Separate Condition entry is allowed for each DG.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more DGs with fuel oil level < 33,000 gal and > 29,500 gal in storage tank.	A.1 Restore fuel oil level to within limits.	48 hours
B. One or more DGs with lube oil inventory < 350 gal and > 300 gal.	B.1 Restore lube oil inventory to within limits.	48 hours
C. One or more DGs with stored fuel oil total particulates not within limit.	C.1 Restore fuel oil total particulates to within limit.	7 days

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.3.1	Verify each fuel oil storage tank contains ≥ 33,000 gal of fuel.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.3.2	Verify lube oil inventory is ≥ 350 gal.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.3.3	Verify fuel oil properties of new and stored fuel oil are tested in accordance with, and maintained within the limits of, the Diesel Fuel Oil Testing Program.	In accordance with the Diesel Fuel Oil Testing Program
SR 3.8.3.4	Verify each DG air start receiver pressure is ≥ 225 psig.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.3.5	Check for and remove accumulated water from each fuel oil storage tank.	In accordance with the Surveillance Frequency Control Program.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

EXELON GENERATION COMPANY, LLC

PSEG NUCLEAR LLC

DOCKET NO. 50-278

PEACH BOTTOM ATOMIC POWER STATION, UNIT 3

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 296
Renewed License No. DPR-56

1. The Nuclear Regulatory Commission (the Commission) has found that:

    A. The application for amendment by Exelon Generation Company, LLC (Exelon Generation Company), and PSEG Nuclear LLC (the licensees), dated September 28, 2012, as supplemented by letters dated February 15, 2013, May 7, 2013, May 24, 2013, June 4, 2013, June 27, 2013, July 30, 2013, July 31, 2013, August 5, 2013, August 22, 2013, August 29, 2013, September 13, 2013, October 11, 2013, October 15, 2013, October 31, 2013, December 6, 2013, December 20, 2013, January 17, 2014, January 31, 2014 (two letters), February 20, 2014, February 28, 2014, March 10, 2014, March 17, 2014, April 11, 2014, April 18, 2014, May 6, 2014, June 5, 2014, and June 20, 2014, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

    B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

    C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

    D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

    E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraphs 2.C(1) and 2.C(2) of Renewed Facility Operating License No. DPR-56 are hereby amended to read as follows:

   (1) Maximum Power Level

   Exelon Generation Company is authorized to operate the Peach Bottom Atomic Power Station, Unit No. 3, at steady state reactor core power levels not in excess of 3951 megawatts thermal.

   (2) Technical Specifications

   The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 296, are hereby incorporated in the renewed license. Exelon Generation Company shall operate the facility in accordance with the Technical Specifications.

3. In addition, Renewed Facility Operating License No. DPR-56 is amended by the addition of new license condition 2.C(15), "Potential Adverse Flow Effects," as indicated in the attachment to this amendment.

4. This license amendment is effective as of its date of issuance and shall be implemented prior to startup from refueling outage P3R20.

FOR THE NUCLEAR REGULATORY COMMISSION

Daniel H. Dorman, Acting Director
Office of Nuclear Reactor Regulation

Attachment: Changes to the License and
Technical Specifications

Date of Issuance: August 25, 2014

ATTACHMENT TO LICENSE AMENDMENT NO. 296

RENEWED FACILITY OPERATING LICENSE NO. DPR-56

DOCKET NO. 50-278

Replace the following pages of the Renewed Facility Operating License with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove	Insert
3	3
- - -	7b
- - -	7c
- - -	7d
- - -	7e
- - -	7f
- - -	7g

Replace the following pages of the Appendix A Technical Specifications with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove	Insert
1.1-5	1.1-5
2.0-1	2.0-1
3.1-21	3.1-21
3.1-22	3.1-22
3.1-23	3.1-23
3.1-24	3.1-24
3.1-25	3.1-25
3.2-1	3.2-1
3.2-2	3.2-2
3.2-4	3.2-4
3.3-2	3.3-2
3.3-3	3.3-3
3.3-3a	3.3-3a
3.3-6	3.3-6
3.3-6a	3.3-6a
3.3-7	3.3-7
3.3-8	3.3-8
3.3-22	3.3-22
3.3-31a	3.3-31a
3.3-31b	3.3-31b
3.3-31c	3.3-31c
3.3-41	3.3-41
3.3-52	3.3-52
3.4-7	3.4-7
3.4-8	3.4-8
3.4-9	3.4-9

Remove	Insert
3.5-5	3.5-5
3.5-11	3.5-11
3.6-16	3.6-16
3.6-28	3.6-28
3.6-30	3.6-30
3.6-30b	3.6-30b
3.7-1	3.7-1
3.7-2	3.7-2
3.7-12	3.7-12
3.8-25	3.8-25
3.8-27	3.8-27

(5) Exelon Generation Company, pursuant to the Act and 10 CFR Parts 30 and 70, to possess, but not to separate, such byproduct and special nuclear material as may be produced by operation of the facility, and such Class B and Class C low-level radioactive waste as may be produced by the operation of Limerick Generating Station, Units 1 and 2.

C. This renewed license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations in 10 CFR Chapter I: Part 20, Section 30.34 of Part 30, Section 40.41 of Part 40, Section 50.54 of Part 50, and Section 70.32 of Part 70; all applicable provisions of the Act and the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified below:

(1) Maximum Power Level

Exelon Generation Company is authorized to operate the Peach Bottom Atomic Power Station, Unit No. 3, at steady state reactor core power levels not in excess of 3951 megawatts thermal.

(2) Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 296, are hereby incorporated in the license. Exelon Generation Company shall operate the facility in accordance with the Technical Specifications.[1]

(3) Physical Protection

Exelon Generation Company shall fully implement and maintain in effect all provisions of the Commission-approved physical security, training and qualification, and safeguards contingency plans including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions to 10 CFR 73.55 (51 FR 27817 and 27822), and the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The combined set of plans[2], submitted by letter dated May 17, 2006, is entitled: "Peach Bottom Atomic Power Station Security Plan, Training and Qualification Plan, Safeguards Contingency Plan, and Independent Spent Fuel Storage Installation Security Program, Revision 3." The set contains Safeguards Information protected under 10 CFR 73.21.

Exelon Generation Company shall fully implement and maintain in effect all provisions of the Commission-approved cyber security plan (CSP), including changes made pursuant to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The Exelon Generation Company CSP was approved by License Amendment No. 283.

[1]Licensed power level was revised by Amendment No. 250, dated November 22, 2002, and will be implemented following the 14th refueling outage currently scheduled for Fall 2003.

[2]The training and Qualification Plan and Safeguards Contingency Plan and Appendices to the Security Plan.

3) For the period up to December 31, 2013, cells whose minimum panel Boron-10 areal density is between 0.014 grams per square centimeter and 0.0112 grams per square centimeter may be used as restricted cells. Restricted cells will only contain Peach Bottom Unit 3 GE14 fuel assemblies with an assembly average burnup of greater than 47,400 megawatt days per metric ton. The minimum panel Boron-10 areal density shall be evaluated by assuming that the panel areal density was initially equal to a value of 0.0235 grams per square centimeter.

(b) Until the installation of NETCO-SNAP-IN® rack inserts are completed in the Peach Bottom Unit 3 spent fuel pool, Boraflex degradation shall be monitored analytically every 6 months.

(c) Boraflex degradation shall be monitored by in-situ testing in the Peach Bottom Unit 3 spent fuel pool no later than December 31, 2013, unless installation of the NETCO-SNAP-IN® rack inserts for Unit 3 have been completed prior to this date.

(d) Installation of NETCO-SNAP-IN® rack inserts shall be completed by December 31, 2016.

(15) Potential Adverse Flow Effects

In conjunction with the license amendment to revise paragraph 2.C(1) of Renewed Facility Operating License No. DPR-56, for Peach Bottom Unit 3, to reflect the new maximum licensed reactor core power level of 3951 megawatts thermal (MWt), the license is also amended to add the following license condition. 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). This license condition is applicable to the initial power ascension from 3514 MWt to the extended power uprate (EPU) power level of 3951 MWt:

(a) The following requirements are placed on the initial operation of the facility, above the thermal power level of 3514 MWt, for the power ascension to 3951 MWt. These conditions are applicable until the first time full EPU conditions (3951 MWt) are achieved. If the number of active main steam line (MSL) strain gauges is less than two strain gauges (180 degrees apart) at any of the eight MSL locations, Exelon Generation Company will stop power ascension and repair/replace the damaged strain gauges and only then resume power ascension.

1. At least 90 days prior to the start of the Peach Bottom Unit 3 EPU outage, Exelon Generation Company shall revise the Peach Bottom Unit 3 replacement steam dryer (RSD) analysis utilizing the Unit 2 on-dryer strain gauge based end-to-end Bias errors and Uncertainties (B/Us) at EPU conditions, and submit the information including the updated limit curves and a list of dominant frequencies for Unit 3, to the NRC as a report in accordance with 10 CFR 50.4.

2. Exelon Generation Company shall evaluate the Unit 3 limit curves prepared in (a)1 above based on new MSL strain gauge data collected following the Unit 3 EPU outage at or near 3514 MWt. If the limit curves change, the new post-EPU outage limit curves shall be provided by e-mail to the NRC Project Manager. Exelon Generation Company shall not increase power above 3514 MWt for at least 96 hours after the NRC Project Manager confirms receipt of the reports unless, prior to expiration of the 96 hour period, the NRC Project Manager advises that the NRC staff has no objections to the continuation of power ascension.

3. Exelon Generation Company shall provide a brief vibration summary report, for piping and valves vibration data collected at or near 3514 MWt, for NRC review before increasing power above 3514 MWt. The summary report shall be provided by e-mail to the NRC Project Manager. Exelon Generation Company shall not increase power above 3514 MWt for at least 96 hours after the NRC Project Manager confirms receipt of the report unless, prior to expiration of the 96 hour period, the NRC Project Manager advises that the NRC staff has no objections to the continuation of power ascension. The vibration summary report shall include the information in items a through c, as follows:

    a. Vibration data for piping and valve locations deemed prone to vibration and vibration monitoring locations identified in Attachment 13 to the EPU application dated September 28, 2012, and Supplement 16 dated December 20, 2013, including the following locations: MSLs (including those in the drywell, turbine building and in the steam tunnel), Feedwater Lines (including those in the drywell and turbine building), Safety Relief Valves (SRVs) and the Main Steam Isolation Valves in the drywell.

    b. An evaluation of the measured vibration data collected in item 3.a above compared against acceptance limits.

    c. Predicted vibration values and associated acceptance limits at approximately 104 percent, 108 percent and 112.4 percent of 3514 MWt using the data collected in item 3.a above.

4. Exelon Generation Company shall monitor the MSL strain gauges during power ascension above 3514 MWt for increasing pressure fluctuations in the steam lines. Upon the initial increase of power above 3514 MWt until reaching 3951 MWt, Exelon Generation Company shall collect data from the MSL strain gauges at nominal 2 percent thermal power increments and evaluate steam dryer performance based on this data.

5. During power ascension at each nominal 2 percent power level above 3514 MWt, Exelon Generation Company shall compare the MSL data to the approved limit curves based on end-to-end B/Us from the Peach Bottom Unit 2 benchmarking at EPU conditions and determine the minimum alternating stress ratio (MASR). A summary of the results shall be provided for NRC review at approximately 104 percent and 108 percent of 3514 MWt. The summary report shall be provided to the NRC Project Manager via e-mail.

6. Exelon Generation Company shall hold the facility at approximately 104 percent and 108 percent of 3514 MWt to perform the following:

    a. Collect strain data from the MSL strain gauges.

    b. Collect vibration data for the locations included in the vibration summary report discussed above.

    c. Evaluate steam dryer performance based on MSL strain gauge data.

    d. Evaluate the measured vibration data (collected in item 6.b above) at that power level, data projected to EPU conditions, trends, and comparison with the acceptance limits.

    e. Provide the steam dryer evaluation and the vibration evaluation, including the data collected, via e-mail to the NRC Project Manager, upon completion of the evaluation for each of the hold points.

    f. Exelon Generation Company shall not increase power above each hold point until 96 hours after the NRC Project Manager confirms receipt of the evaluations unless, prior to the expiration of the 96 hour period, the NRC Project Manager advises that the NRC staff has no objections to the continuation of power ascension.

7. If any frequency peak from the MSL strain gauge data exceeds the Level 1 limit curves, Exelon Generation Company shall return the facility to a power level at which the limit curve is not exceeded. Exelon Generation Company shall resolve the discrepancy, evaluate and document the continued structural integrity of the steam dryer, and provide that documentation to the NRC Project Manager via e-mail prior to further increases in reactor power. If a revised stress analysis is performed and new limit curves are developed, then Exelon Generation Company shall not further increase power above each hold point until 96 hours after the NRC Project Manager confirms receipt of the documentation or until the NRC Project Manager advises that the NRC staff has no objections to the continuation of power ascension, whichever comes first. Additional detail is provided in paragraph (b)1 below.

(b) Exelon Generation Company shall implement the following actions for the initial power ascension from 3514 MWt to 3951 MWt condition:

1. In the event that acoustic signals (in MSL strain gauge signals) are identified that exceed the Level 1 limit curves during power ascension above 3514 MWt, Exelon Generation Company shall re-evaluate dryer loads and stresses, and re-establish the limit curves. In the event that stress analyses are re-performed based on new strain gauge data to address paragraph (a)7 above, the revised load definition, stress analysis, and limit curves shall include:

   a. Application of end-to-end B/Us as determined from Peach Bottom Unit 2 EPU measurements.

   b. Use of bump-up factors associated with all of the SRV acoustic resonances as determined from the scale model test results or in-plant data acquired during power ascension.

2. After reaching 3951 MWt, Exelon Generation Company shall obtain measurements from the MSL strain gauges 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 load definition. These data will be provided to the NRC staff as described below in paragraph (e).

(c) Exelon Generation Company shall prepare the EPU power ascension test procedure to include:

1. The MSL strain gage limit curves to be applied for evaluating steam dryer performance, based on end-to-end B/Us from Peach Bottom Unit 2 benchmarking at EPU conditions.

2. Specific hold points and their durations during EPU power ascension.

3. Activities to be accomplished during the hold points.

4. Plant parameters to be monitored.

5. Inspections and walkdowns to be conducted for steam, feedwater, and condensate systems and components during the hold points.

6. Methods to be used to trend plant parameters.

7. Acceptance criteria for monitoring and trending plant parameters, and conducting the walkdowns and inspections.

8. Actions to be taken if acceptance criteria are not satisfied.

9. Verification of the completion of commitments and planned actions specified in the 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 3514 MWt. Exelon Generation Company shall provide the related EPU startup test procedure sections to the NRC Project Manager via e-mail prior to increasing power above 3514 MWt.

(d) 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:

1. During initial power ascension testing above 3514 MWt, each of the two hold points shall be at increments of approximately 4 percent of 3514 MWt.

2. Level 1 performance criteria.

3. The methodology for establishing the limit curves used for the Level 1 and Level 2 performance.

(e) 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 in accordance with 10 CFR 50.4. The report shall include a final load definition and stress report of the steam dryer, including the results of a complete re-analysis using the end-to-end B/Us from Peach Bottom Unit 2 benchmarking at EPU conditions. The report shall be submitted within 90 days of the completion of EPU power ascension testing for Peach Bottom Unit 3.

(f) During the first two scheduled refueling outages after reaching EPU conditions, a visual inspection shall be conducted of the steam dryer as described in the inspection guidelines contained in WCAP-17635-P.

(g) The results of the visual inspections of the steam dryer shall be submitted to the NRC staff in a report in accordance with 10 CFR 50.4. The report shall be submitted within 90 days following startup from each of the first two respective refueling outages.

(h) Within 6 months following completion of the second refueling outage, after the implementation of the EPU, the licensee shall submit a long-term steam dryer inspection plan based on industry operating experience along with the baseline inspection results.

The license condition described above shall expire: (1) upon satisfaction of the requirements in paragraphs (f) and (g), provided that a visual inspection of the steam dryer does not reveal any new unacceptable flaw(s) or unacceptable flaw growth that is due to fatigue, and; (2) upon satisfaction of the requirements specified in paragraph (h).

3. This renewed license is subject to the following conditions for the protection of the environment:

A. To the extent matters related to thermal discharges are treated therein, operation of Peach Bottom Atomic Power Station, Unit No. 3, will be governed by NPDES Permit No. PA 0009733, as now in effect and as hereafter amended. Questions pertaining to conformance thereto shall be referred to and shall be determined by the NPDES Permit issuing or enforcement authority, as appropriate.

B. In the event of any modification of the NPDES Permit related to thermal discharges or the establishment (or amendment) of alternative effluent limitations established pursuant to Section 316 of the Federal Water Pollution Control Act, the Exelon Generation Company shall inform the NRC and analyze any associated changes in or to the Station, its components, its operation or in the discharge of effluents therefrom. If such change would entail any modification to

1.1 Definitions

PHYSICS TESTS (continued)	b. Authorized under the provisions of 10 CFR 50.59; or c. Otherwise approved by the Nuclear Regulatory Commission.
PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)	The PTLR is the unit-specific document that provides the reactor vessel pressure and temperature limits, including heatup and cooldown rates, for the current reactor vessel fluence period. These pressure and temperature limits shall be determined for each fluence period in accordance with Specification 5.6.7.
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of 3951 MWt.
REACTOR PROTECTION SYSTEM (RPS) RESPONSE TIME	The RPS RESPONSE TIME shall be that time interval from the opening of the sensor contact up to and including the opening of the trip actuator contacts.
RECENTLY IRRADIATED FUEL	RECENTLY IRRADIATED FUEL is fuel that has occupied part of a critical reactor core within the previous 24 hours. When using this definition to suspend the Applicability of LCOs, secondary containment ground-level hatches H20, H21, H22, H23, H24, and H34 shall be closed during the movement of any irradiated fuel in Secondary Containment.
SHUTDOWN MARGIN (SDM)	SDM shall be the amount of reactivity by which the reactor is subcritical or would be subcritical assuming that: a. The reactor is xenon free; b. The moderator temperature is 68°F; and c. All control rods are fully inserted except for the single control rod of highest reactivity worth, which is assumed to be fully withdrawn. With control rods not capable of being fully inserted, the reactivity worth of these control rods must be accounted for in the determination of SDM.

(continued)

2.0 SAFETY LIMITS (SLs)

2.1 SLs

2.1.1 Reactor Core SLs

2.1.1.1 With the reactor steam dome pressure < 785 psig or core flow < 10% rated core flow:

THERMAL POWER shall be ≤ 23% RTP.

2.1.1.2 With the reactor steam dome pressure ≥ 785 psig and core flow ≥ 10% rated core flow:

MCPR shall be ≥ 1.09 for two recirculation loop operation or ≥ 1.12 for single recirculation loop operation.

2.1.1.3 Reactor vessel water level shall be greater than the top of active irradiated fuel.

2.1.2 Reactor Coolant System Pressure SL

Reactor steam dome pressure shall be ≤ 1325 psig.

2.2 SL Violations

With any SL violation, the following actions shall be completed within 2 hours:

2.2.1 Restore compliance with all SLs; and

2.2.2 Insert all insertable control rods.

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. Two SLC subsystems inoperable for reasons other than Condition A.	C.1	Restore one SLC subsystem to OPERABLE status.	8 hours
D. Required Action and associated Completion Time not met.	D.1	Be in MODE 3.	12 hours
	<u>AND</u>		
	D.2	Be in MODE 4.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.7.1	Verify level of sodium pentaborate solution in the SLC tank is ≥ 52%.	In accordance with the Surveillance Frequency Control Program.
SR 3.1.7.2	Verify temperature of sodium pentaborate solution is ≥ 53°F.	In accordance with the Surveillance Frequency Control Program.
SR 3.1.7.3	Verify temperature of pump suction piping is ≥ 53°F.	In accordance with the Surveillance Frequency Control Program.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.1.7.4	Verify continuity of explosive charge.	In accordance with the Surveillance Frequency Control Program.
SR 3.1.7.5	Verify the concentration of boron in solution is ≥ 8.32% weight and ≤ 9.82% weight.	In accordance with the Surveillance Frequency Control Program. AND Once within 24 hours after water or boron is added to solution AND Once within 24 hours after solution temperature is restored within limits
SR 3.1.7.6	Verify each SLC subsystem manual and power operated valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position, or can be aligned to the correct position.	In accordance with the Surveillance Frequency Control Program.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.1.7.7	Deleted	
SR 3.1.7.8	Verify each pump develops a flow rate ≥ 49.1 gpm at a discharge pressure ≥ 1275 psig.	In accordance with the Inservice Testing Program
SR 3.1.7.9	Verify flow through one SLC subsystem from pump into reactor pressure vessel.	In accordance with the Surveillance Frequency Control Program.
SR 3.1.7.10	Verify sodium pentaborate enrichment is ≥ 92.0 atom percent B-10.	In accordance with the Surveillance Frequency Control Program. <u>AND</u> Once within 8 hours after addition to SLC tank

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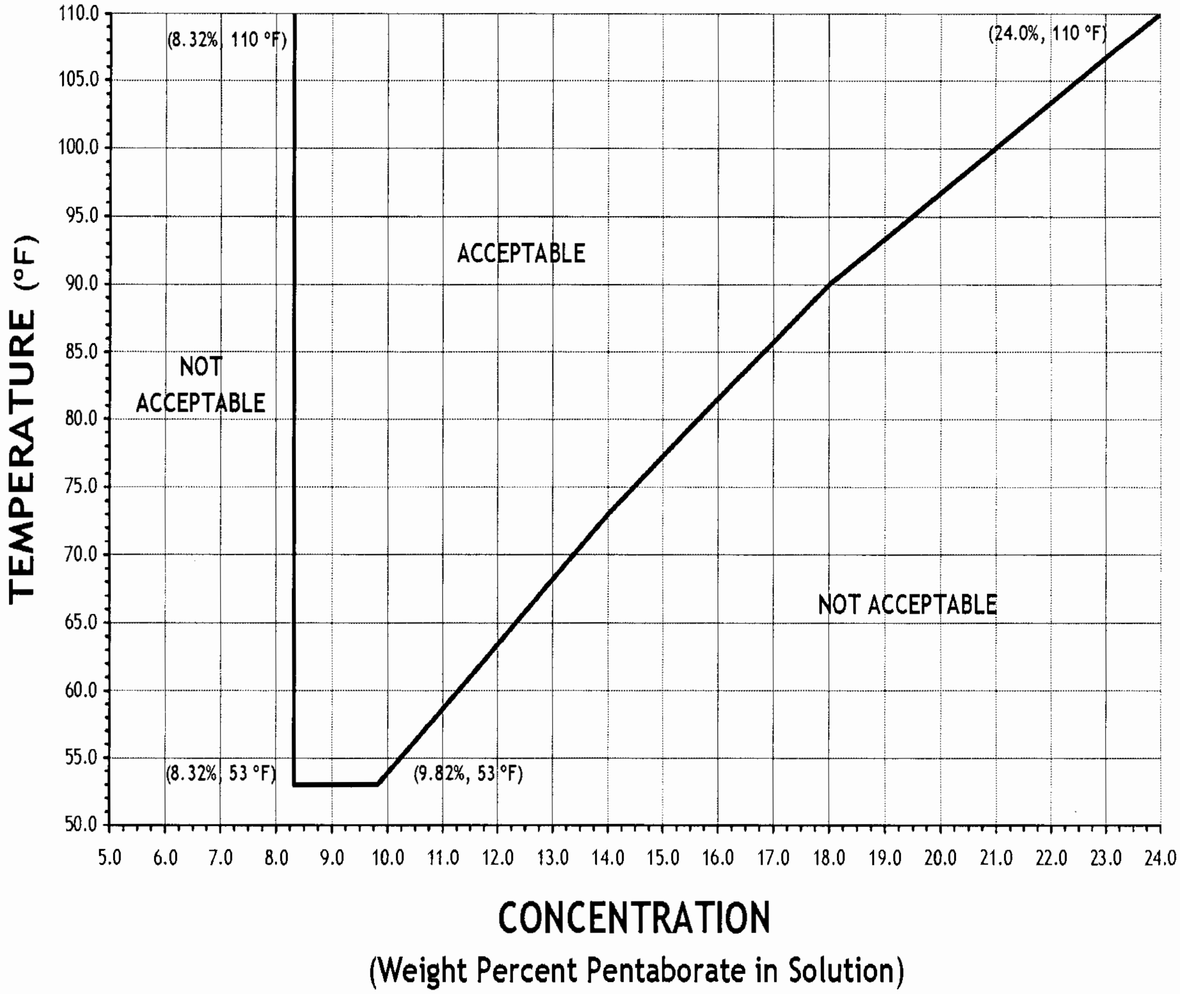

Figure 3.1.7-1 (page 1 of 1)
Sodium Pentaborate Solution Temperature Versus Concentration Requirements

3.2 POWER DISTRIBUTION LIMITS

3.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)

LCO 3.2.1 All APLHGRs shall be less than or equal to the limits specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ 23% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Any APLHGR not within limits.	A.1 Restore APLHGR(s) to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 23% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.2.1.1 Verify all APLHGRs are less than or equal to the limits specified in the COLR.	Once within 12 hours after ≥ 23% RTP <u>AND</u> In accordance with the Surveillance Frequency Control Program.

3.2 POWER DISTRIBUTION LIMITS

3.2.2 MINIMUM CRITICAL POWER RATIO (MCPR)

LCO 3.2.2 All MCPRs shall be greater than or equal to the MCPR operating limits specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ 23% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Any MCPR not within limits.	A.1 Restore MCPR(s) to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 23% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.2.1	Verify all MCPRs are greater than or equal to the limits specified in the COLR.	Once within 12 hours after ≥ 23% RTP AND In accordance with the Surveillance Frequency Control Program.

(continued)

3.2 POWER DISTRIBUTION LIMITS

3.2.3 LINEAR HEAT GENERATION RATE (LHGR)

LCO 3.2.3 All LHGRs shall be less than or equal to the limits specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ 23% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Any LHGR not within limits.	A.1 Restore LHGR(s) to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 23% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.2.3.1 Verify all LHGRs are less than or equal to the limits specified in the COLR.	Once within 12 hours after ≥ 23% RTP <u>AND</u> In accordance with the Surveillance Frequency Control Program.

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One or more automatic Functions with RPS trip capability not maintained. <u>OR</u> Two or more manual Functions with RPS trip capability not maintained.	C.1	Restore RPS trip capability.	1 hour
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1	Enter the Condition referenced in Table 3.3.1.1-1 for the channel.	Immediately
E. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	E.1	Reduce THERMAL POWER to < 26.7% RTP.	4 hours
F. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	F.1	Be in MODE 2.	6 hours
G. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	G.1	Be in MODE 3.	12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
H. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	H.1	Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately
I. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	I.1	Initiate alternate method to detect and suppress thermal hydraulic instability oscillations.	12 hours
	<u>AND</u>		
	I.2	--------NOTE-------- LCO 3.0.4 is not applicable. -------------------- Restore required channels to OPERABLE.	 120 days
J. Required Action and associated Completion Time of Condition I not met.	J.1	Reduce THERMAL POWER to <23% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

------------------------------------NOTES------------------------------------

1. Refer to Table 3.3.1.1-1 to determine which SRs apply for each RPS Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains RPS trip capability.

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.1.2	------------------NOTE------------------ Not required to be performed until 12 hours after THERMAL POWER ≥ 23% RTP. -- Verify the absolute difference between the average power range monitor (APRM) channels and the calculated power is ≤ 2% RTP while operating at ≥ 23% RTP.	In accordance with the Surveillance Frequency Control Program.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.12	------------------NOTES------------------ 1. Neutron detectors are excluded. 2. For Function 1, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. 3. For Functions 2.b and 2.f, the recirculation flow transmitters that feed the APRMs are included. --- Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.1.13	Verify Turbine Stop Valve-Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure-Low Functions are not bypassed when THERMAL POWER is ≥ 26.7% RTP.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.1.14	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.1.15	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.16	Calibrate each radiation detector.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.1.17	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.1.18	Verify the RPS RESPONSE TIME is within limits.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.1.19	Verify OPRM is not bypassed when APRM Simulated Thermal Power is ≥ 26.2% and recirculation drive flow is <60%.	In accordance with the Surveillance Frequency Control Program.

Table 3.3.1.1-1 (page 1 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Wide Range Neutron Monitors					
a. Period-Short	2	3	G	SR 3.3.1.1.1 SR 3.3.1.1.5 SR 3.3.1.1.12 SR 3.3.1.1.17 SR 3.3.1.1.18	≥ 13 seconds
	5(a)	3	H	SR 3.3.1.1.1 SR 3.3.1.1.6 SR 3.3.1.1.12 SR 3.3.1.1.17 SR 3.3.1.1.18	≥ 13 seconds
b. Inop	2	3	G	SR 3.3.1.1.5 SR 3.3.1.1.17	NA
	5(a)	3	H	SR 3.3.1.1.6 SR 3.3.1.1.17	NA
2. Average Power Range Monitors					
a. Neutron Flux-High (Setdown)	2	3(c)	G	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.11 SR 3.3.1.1.12	≤ 15.0% RTP
b. Simulated Thermal Power-High	1	3(c)	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.8 SR 3.3.1.1.11 SR 3.3.1.1.12 (e),(f)	≤ 0.55 W + 63.3% RTP(b) and ≤ 118.0% RTP
c. Neutron Flux-High	1	3(c)	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.8 SR 3.3.1.1.11 SR 3.3.1.1.12	≤ 119.7% RTP
d. Inop	1,2	3(c)	G	SR 3.3.1.1.11	NA
e. 2-Out-Of-4 Voter	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.11 SR 3.3.1.1.17 SR 3.3.1.1.18	NA
f. OPRM Upscale	≥23% RTP	3(c)	I	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.11 SR 3.3.1.1.12 SR 3.3.1.1.19	(d)

(continued)

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

(b) 0.55 (W - ΔW) + 61.5% RTP when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating."

(c) Each APRM channel provides inputs to both trip systems.

(d) See COLR for OPRM period based detection algorithm (PBDA) setpoint limits.

(e) If the as-found channel setpoint is outside its predefined as-found tolerance, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.

(f) The instrument channel set point shall be reset to a value that is within the Leave Alone Zone (LAZ) around the Nominal Trip Setpoint (NTSP) at the completion of the surveillance; otherwise, the channel shall be declared inoperable. Setpoints more conservative than the NTSP are acceptable provided the as-found tolerance and LAZ apply to the actual setpoint implemented in the Surveillance procedures to confirm channel performance. The NTSP methodologies used to determine the as-found tolerance and the LAZ are specified in the Bases associated with the specified function.

Table 3.3.1.1-1 (page 2 of 3)
Reactor Protection System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
3.	Reactor Pressure - High	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.9 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 1085.0 psig
4.	Reactor Vessel Water Level - Low (Level 3)	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.9 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≥ 1.0 inches
5.	Main Steam Isolation Valve - Closure	1	8	F	SR 3.3.1.1.9 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 10% closed
6.	Drywell Pressure - High	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.9 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 2.0 psig
7.	Scram Discharge Volume Water Level - High	1,2	2	G	SR 3.3.1.1.9 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 50.0 gallons
		5[a]	2	H	SR 3.3.1.1.9 SR 3.3.1.1.15 SR 3.3.1.1.17	≤ 50.0 gallons
8.	Turbine Stop Valve - Closure	≥ 26.7% RTP	4	E	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 10% closed
9.	Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	≥ 26.7% RTP	2	E	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≥ 500.0 psig
10.	Turbine Condenser - Low Vacuum	1	2	F	SR 3.3.1.1.1 SR 3.3.1.1.9 SR 3.3.1.1.15 SR 3.3.1.1.17 SR 3.3.1.1.18	≥ 23.0 inches Hg vacuum
11.	Main Steam Line - High Radiation	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.10 SR 3.3.1.1.16 SR 3.3.1.1.17 SR 3.3.1.1.18	≤ 15 X Full Power Background
12.	Reactor Mode Switch - Shutdown Position	1,2	1	G	SR 3.3.1.1.14 SR 3.3.1.1.17	NA
		5[a]	1	H	SR 3.3.1.1.14 SR 3.3.1.1.17	NA

(continued)

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

3.3 INSTRUMENTATION

3.3.2.2 Feedwater and Main Turbine High Water Level Trip Instrumentation

LCO 3.3.2.2 Two channels per trip system of the Digital Feedwater Control System (DFCS) high water level trip instrumentation Function shall be OPERABLE.

APPLICABILITY: THERMAL POWER ≥ 23% RTP.

ACTIONS

------------------------------------NOTE------------------------------------
Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more DFCS high water level trip channels inoperable.	A.1	Place channel in trip.	72 hours
B. DFCS high water level trip capability not maintained.	B.1	Restore DFCS high water level trip capability.	2 hours
C. Required Action and associated Completion Time not met.	C.1	--------NOTE--------- Only applicable if inoperable channel is the result of inoperable feedwater pump turbine or main turbine stop valve. --------------------	
		Remove affected feedwater pump(s) and main turbine valve(s) from service.	4 hours
	OR		
	C.2	Reduce THERMAL POWER to < 23% RTP.	4 hours

3.3 INSTRUMENTATION

3.3.4.2 End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation

LCO 3.3.4.2

a. Two channels per trip system for each EOC-RPT instrumentation Function listed below shall be OPERABLE:

1. Turbine Stop Valve (TSV)—Closure; and

2. Turbine Control Valve (TCV) Fast Closure, Trip Oil Pressure—Low.

<u>OR</u>

b. The following limits are made applicable:

1. LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," limits for inoperable EOC-RPT as specified in the COLR;

2. LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," limits for inoperable EOC-RPT as specified in the COLR; and

3. LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)," limits for inoperable EOC-RPT as specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ 26.7% RTP.

ACTIONS

------------------------------------NOTE------------------------------------
Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more required channels inoperable.	A.1	Restore channel to OPERABLE status.	72 hours
	<u>OR</u>		
	A.2	--------NOTE--------- Not applicable if inoperable channel is the result of an inoperable breaker. ---------------------	
		Place channel in trip.	72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One or more Functions with EOC-RPT trip capability not maintained.	B.1	Restore EOC-RPT trip capability.	2 hours
C. Required Action and associated Completion Time not met.	C.1	--------NOTE--------- Only applicable if inoperable channel is the result of an inoperable RPT breaker. --------------------	
		Remove the affected recirculation pump from service.	4 hours
	<u>OR</u>		
	C.2	Reduce THERMAL POWER to < 26.7% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

-----------------------------------NOTE-----------------------------------
When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains EOC-RPT trip capability.

SURVEILLANCE		FREQUENCY
SR 3.3.4.2.1	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.4.2.2	Perform CHANNEL CALIBRATION. The Allowable Values shall be: TSV—Closure: ≤ 10% closed; and TCV Fast Closure, Trip Oil Pressure—Low: ≥ 500 psig.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.4.2.3	Perform LOGIC SYSTEM FUNCTIONAL TEST including breaker actuation.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.4.2.4	Verify TSV—Closure and TCV Fast Closure, Trip Oil Pressure—Low Functions are not bypassed when THERMAL POWER is ≥ 26.7% RTP.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.4.2.5	------------------NOTE------------------ Breaker interruption time may be assumed from the most recent performance of SR 3.3.4.2.6. -- Verify the EOC-RPT SYSTEM RESPONSE TIME is within limits.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.4.2.6	Determine RPT breaker interruption time.	In accordance with the Surveillance Frequency Control Program.

Table 3.3.5.1-1 (page 3 of 5)
Emergency Core Cooling System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
3. High Pressure Coolant Injection (HPCI) System					
a. Reactor Vessel Water Level—Low Low (Level 2)	1, $2^{(d)}$, $3^{(d)}$	4	B	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ -48.0 inches
b. Drywell Pressure—High	1, $2^{(d)}$, $3^{(d)}$	4	B	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≤ 2.0 psig
c. Reactor Vessel Water Level—High (Level 8)	1, $2^{(d)}$, $3^{(d)}$	2	C	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≤ 46.0 inches
d. Condensate Storage Tank Level—Low	1, $2^{(d)}$, $3^{(d)}$	2	D	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ 5.25 ft above tank bottom
e. Suppression Pool Water Level—High	1, $2^{(d)}$, $3^{(d)}$	2	D	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≤ 16 ft 7 inches
f. High Pressure Coolant Injection Pump Discharge Flow—Low (Bypass)	1, $2^{(d)}$, $3^{(d)}$	1	E	SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ 3.5 in-wc and ≤ 19.0 in-wc
4. Automatic Depressurization System (ADS) Trip System A					
a. Reactor Vessel Water Level—Low Low Low (Level 1)	1, $2^{(e)}$, $3^{(e)}$	2	F	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ -160.0 inches
b. Drywell Pressure—High	1, $2^{(e)}$, $3^{(e)}$	2	F	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≤ 2.0 psig
c. Automatic Depressurization System Initiation Timer	1, $2^{(e)}$, $3^{(e)}$	1	G	SR 3.3.5.1.4 SR 3.3.5.1.5	≤ 115.0 seconds

(continued)

(d) With reactor steam dome pressure > 150 psig.

(e) With reactor steam dome pressure > 100 psig.

Table 3.3.6.1-1 (page 1 of 3)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Main Steam Line Isolation					
a. Reactor Vessel Water Level – Low Low Low (Level 1)	1,2,3	2	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.7	≥ -160.0 inches
b. Main Steam Line Pressure – Low	1	2	E	SR 3.3.6.1.3 SR 3.3.6.1.7	≥ 825.0 psig
c. Main Steam Line Flow – High	1,2,3	2 per MSL	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.7	≤ 173.8 psid
d. Main Steam Line – High Radiation	1,2,3	2	D	SR 3.3.6.1.1 SR 3.3.6.1.3 SR 3.3.6.1.6 SR 3.3.6.1.7	≤ 15 X Full Power Background
e. Main Steam Tunnel Temperature – High	1,2,3	8	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.7	≤ 200.0°F
2. Primary Containment Isolation					
a. Reactor Vessel Water Level – Low (Level 3)	1,2,3	2	G	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.7	≥ 1.0 inches
b. Drywell Pressure – High	1,2,3	2	G	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.7	≤ 2.0 psig
c. Main Stack Monitor Radiation – High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.7	≤ 2 X 10^{-2} μCi/cc
d. Reactor Building Ventilation Exhaust Radiation – High	1,2,3	2	G	SR 3.3.6.1.1 SR 3.3.6.1.3 SR 3.3.6.1.7	≤ 16.0 mR/hr
e. Refueling Floor Ventilation Exhaust Radiation – High	1,2,3	2	G	SR 3.3.6.1.1 SR 3.3.6.1.3 SR 3.3.6.1.7	≤ 16.0 mR/hr

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.2.1	------------------NOTES------------------ 1. Not required to be performed until 4 hours after associated recirculation loop is in operation. 2. Not required to be performed until 24 hours after > 23% RTP. --- Verify at least one of the following criteria (a, b, or c) is satisfied for each operating recirculation loop: a. Recirculation pump flow to speed ratio differs by ≤ 5% from established patterns, and jet pump loop flow to recirculation pump speed ratio differs by ≤ 5% from established patterns. b. Each jet pump diffuser to lower plenum differential pressure differs by ≤ 20% from established patterns. c. Each jet pump flow differs by ≤ 10% from established patterns.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.3 Safety Relief Valves (SRVs) and Safety Valves (SVs)

LCO 3.4.3 The safety function of 13 valves (any combination of SRVs and SVs) shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required SRVs or SVs inoperable.	A.1 Be in MODE 3. AND A.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.3.1	Verify the safety function lift setpoints of the required SRVs and SVs are as follows: Number of SRVs / Setpoint (psig) 4 / 1135 ± 34.1 4 / 1145 ± 34.4 3 / 1155 ± 34.7 Number of SVs / Setpoint (psig) 3 / 1260 ± 37.8 Following testing, lift settings shall be within ± 1%.	In accordance with the Inservice Testing Program
SR 3.4.3.2	Verify each required SRV actuator strokes when manually actuated in the depressurization mode.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.1.5	-------------------NOTE------------------- Not required to be performed if performed within the previous 31 days. -- Verify each recirculation pump discharge valve cycles through one complete cycle of full travel or is de-energized in the closed position.	 Once each startup prior to exceeding 23% RTP
SR 3.5.1.6	Verify automatic transfer of the power supply from the normal source to the alternate source for each LPCI subsystem inboard injection valve and each recirculation pump discharge valve.	In accordance with the Surveillance Frequency Control Program.
SR 3.5.1.7	-------------------NOTE------------------- For the core spray pumps, SR 3.5.1.7 may be met using equivalent values for flow rate and test pressure determined using pump curves. -- Verify the following ECCS pumps develop the specified flow rate against a system head corresponding to the specified reactor pressure. SYSTEM / FLOW RATE / NO. OF PUMPS / SYSTEM HEAD CORRESPONDING TO A REACTOR PRESSURE OF Core Spray / ≥ 3,125 gpm / 1 / ≥ 105 psig LPCI / ≥ 8,600 gpm / 1 / ≥ 20 psig	 In accordance with the Surveillance Frequency Control Program.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.2.5	-------------------NOTE------------------- For the CS pumps, SR 3.5.2.5 may be met using equivalent values for flow rate and test pressure determined using pump curves. -- Verify each required ECCS pump develops the specified flow rate against a system head corresponding to the specified reactor pressure. SYSTEM / FLOW RATE / NO. OF PUMPS / SYSTEM HEAD CORRESPONDING TO A REACTOR PRESSURE OF CS / ≥ 3,125 gpm / 1 / ≥ 105 psig LPCI / ≥ 8,600 gpm / 1 / ≥ 20 psig	In accordance with the Surveillance Frequency Control Program.
SR 3.5.2.6	-------------------NOTE------------------- Vessel injection/spray may be excluded. -- Verify each required ECCS injection/spray subsystem actuates on an actual or simulated automatic initiation signal.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.1.3.14	Verify combined MSIV leakage rate for all four main steam lines is ≤ 170 scfh, and ≤ 85 scfh for any one steam line, when tested at ≥ 25 psig.	In accordance with the Primary Containment Leakage Rate Testing Program
SR 3.6.1.3.15	Verify each 6 inch and 18 inch primary containment purge valve and each 18 inch primary containment exhaust valve is blocked to restrict opening greater than the required maximum opening angle.	In accordance with the Surveillance Frequency Control Program.
SR 3.6.1.3.16	Replace the inflatable seal of each 6 inch and 18 inch primary containment purge valve and each 18 inch primary containment exhaust valve.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.3.1	Verify each RHR suppression pool cooling subsystem manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position or can be aligned to the correct position.	In accordance with the Surveillance Frequency Control Program.
SR 3.6.2.3.2	Verify each required RHR pump develops a flow rate ≥ 8,600 gpm through the associated heat exchanger while operating in the suppression pool cooling mode.	In accordance with the Inservice Testing Program
SR 3.6.2.3.3	Verify manual transfer capability of power supply for the RHR motor-operated flow control valve and the RHR cross-tie motor-operated valve from the normal source to the alternate source.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.4.1	Verify each RHR suppression pool spray subsystem manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position or can be aligned to the correct position.	In accordance with the Surveillance Frequency Control Program.
SR 3.6.2.4.2	Verify each suppression pool spray nozzle is unobstructed.	In accordance with the Surveillance Frequency Control Program.
SR 3.6.2.4.3	Verify manual transfer capability of power supply for the RHR motor-operated flow control valve and the RHR cross-tie motor-operated valve from the normal source to the alternate source.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.5.1	Verify each RHR drywell spray subsystem manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position or can be aligned to the correct position.	In accordance with the Surveillance Frequency Control Program.
SR 3.6.2.5.2	Verify each drywell spray nozzle is unobstructed.	In accordance with the Surveillance Frequency Control Program.
SR 3.6.2.5.3	Verify manual transfer capability of power supply for the RHR motor-operated flow control valve and the RHR cross-tie motor-operated valve from the normal source to the alternate source.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.1 High Pressure Service Water (HPSW) System

LCO 3.7.1 Two HPSW subsystems and the HPSW cross tie shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One HPSW subsystem inoperable.	-----------NOTE------------- Enter applicable Conditions and Required Actions of LCO 3.4.7, "Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown," for RHR shutdown cooling made inoperable by HPSW System. ----------------------------	
	A.1 Restore HPSW subsystem to OPERABLE status.	7 days
B. HPSW cross tie inoperable.	B.1 Restore HPSW cross tie to OPERABLE status	7 days
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Be in MODE 3.	12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Both HPSW subsystems inoperable.	-----------NOTE------------- Enter applicable Conditions and Required Actions of LCO 3.4.7 for RHR shutdown cooling made inoperable by HPSW System. ----------------------------	
	D.1 Restore one HPSW subsystem to OPERABLE status.	8 hours
E. Required Action and associated Completion Time of Condition D not met.	E.1 Be in MODE 3.	12 hours
	AND	
	E.2 Be in MODE 4.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.1.1	Verify each HPSW manual and power operated valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position or can be aligned to the correct position.	In accordance with the Surveillance Frequency Control Program.
SR 3.7.1.2	Verify manual transfer capability of power supply for the HPSW cross-tie motor-operated valve and the RHR heat exchanger HPSW outlet valve from the normal source to the alternate source.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.6 Main Turbine Bypass System

LCO 3.7.6 The Main Turbine Bypass System shall be OPERABLE.

<u>OR</u>

The following limits are made applicable:

a. LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," limits for an inoperable Main Turbine Bypass System, as specified in the COLR;

b. LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," limits for an inoperable Main Turbine Bypass System, as specified in the COLR; and

c. LCO 3.2.3, “LINEAR HEAT GENERATION RATE (LHGR),” limits for an inoperable Main Turbine Bypass System, as specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ 23% RTP.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Requirements of the LCO not met.	A.1	Satisfy the requirements of the LCO.	2 hours
B. Required Action and associated Completion Time not met.	B.1	Reduce THERMAL POWER to < 23% RTP.	4 hours

3.8 ELECTRICAL POWER SYSTEMS

3.8.3 Diesel Fuel Oil, Lube Oil, and Starting Air

LCO 3.8.3 The stored diesel fuel oil, lube oil, and starting air subsystem shall be within limits for each required diesel generator (DG).

APPLICABILITY: When associated DG is required to be OPERABLE.

ACTIONS

------------------------------------- NOTE -------------------------------------
Separate Condition entry is allowed for each DG.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more DGs with fuel oil level < 33,000 gal and > 29,500 gal in storage tank.	A.1	Restore fuel oil level to within limits.	48 hours
B. One or more DGs with lube oil inventory < 350 gal and > 300 gal.	B.1	Restore lube oil inventory to within limits.	48 hours
C. One or more DGs with stored fuel oil total particulates not within limit.	C.1	Restore fuel oil total particulates to within limit.	7 days

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.3.1	Verify each fuel oil storage tank contains ≥ 33,000 gal of fuel.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.3.2	Verify lube oil inventory is ≥ 350 gal.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.3.3	Verify fuel oil properties of new and stored fuel oil are tested in accordance with, and maintained within the limits of, the Diesel Fuel Oil Testing Program.	In accordance with the Diesel Fuel Oil Testing Program
SR 3.8.3.4	Verify each DG air start receiver pressure is ≥ 225 psig.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.3.5	Check for and remove accumulated water from each fuel oil storage tank.	In accordance with the Surveillance Frequency Control Program.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NOS. 293 AND 296

TO RENEWED FACILITY OPERATING LICENSE NOS. DPR-44 AND DPR-56

EXELON GENERATION COMPANY, LLC

PSEG NUCLEAR LLC

PEACH BOTTOM ATOMIC POWER STATION, UNITS 2 AND 3

DOCKET NOS. 50-277 AND 50-278

Proprietary information pursuant to
Title 10 of the *Code of Federal Regulations* (10 CFR), Section 2.390
has been redacted from this document.
Redacted information is identified by blank space enclosed within double brackets
as shown here [[ ]].

Enclosure 3

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1.0 INTRODUCTION

1.1 Application

By application dated September 28, 2012 (Reference 1), as supplemented by letters dated February 15, 2013 (Reference 2), May 7, 2013 (Reference 3), May 24, 2013 (Reference 4), June 4, 2013 (Reference 5), June 27, 2013 (Reference 6), July 30, 2013 (Reference 7), July 31, 2013 (Reference 8), August 5, 2013 (Reference 9), August 22, 2013 (Reference 10), August 29, 2013 (Reference 11), September 13, 2013 (Reference 12), October 11, 2013 (Reference 13), October 15, 2013 (Reference 14), October 31, 2013 (Reference 15), December 6, 2013 (Reference 16), December 20, 2013 (Reference 17), January 17, 2014 (Reference 18), January 31, 2014 (Reference 19), January 31, 2014 (Reference 74), February 20, 2014 (Reference 75), February 28, 2014 (Reference 76), March 10, 2014 (Reference 77), March 17, 2014 (Reference 78), April 11, 2014 (Reference 107), April 18, 2014 (Reference 108), May 6, 2014 (Reference 114), June 5, 2014 (Reference 116), and June 20, 2014 (Reference 117), Exelon Generation Company, LLC (Exelon, the licensee) submitted a license amendment request for Peach Bottom Atomic Power Station (PBAPS), Units 2 and 3. The proposed amendment would authorize an increase in the maximum power level from 3514 megawatts thermal (MWt) to 3951 MWt. The requested change, referred to as an extended power uprate (EPU), represents an increase of approximately 12.4 percent above the current licensed thermal power (CLTP) level.

The supplemental letters referenced above provided additional clarifying information that did not expand the scope of the initial application and did not change the U.S. Nuclear Regulatory Commission (NRC or the Commission) staff's original proposed no significant hazards consideration determination as published in the *Federal Register* on April 9, 2013 (78 FR 21164).

1.2 Background

General Site Information

The PBAPS site is located in Peach Bottom Township, York County, Pennsylvania on the west bank of the Susquehanna River. The site is located approximately 38 miles north of Baltimore, Maryland, 19 miles southwest of Lancaster, Pennsylvania, and 30 miles southeast of York, Pennsylvania.

PBAPS, Units 2 and 3, are boiling-water reactor (BWR) plants of the BWR/4 design with Mark I containments. PBAPS, Unit 1, was a high temperature, gas-cooled reactor that is permanently shut down and is currently maintained in an operating SAFSTOR decommissioning condition.

The construction permit for PBAPS, Units 2 and 3, was issued by the Atomic Energy Commission (AEC) on January 31, 1968. Both units began commercial operation in 1974. The renewed licenses for Units 2 and 3 expire in 2033 and 2034, respectively.

Licensing/Design Basis Information

As discussed in Appendix H to the PBAPS Updated Final Safety Analysis Report (UFSAR), during the construction/licensing process, both units were evaluated against the then-current AEC draft of the 27 General Design Criteria (GDC) issued in November 1965. On July 11, 1967, the AEC published for public comment, in the *Federal Register* (32 FR 10213), a revised and expanded set of 70 draft GDC (hereinafter referred to as the "draft GDC"). Appendix H of the PBAPS UFSAR contains an evaluation of the design basis of PBAPS, Units 2 and 3, against the draft GDC. The licensee concluded that PBAPS, Units 2 and 3, conforms to the intent of the draft GDC.

On February 20, 1971, the AEC published in the *Federal Register* (36 FR 3255), a final rule that added Appendix A to Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, "General Design Criteria for Nuclear Power Plants" (hereinafter referred to as the "final GDC"). Differences between the draft GDC and final GDC included a consolidation from 70 to 64 criteria. As discussed in the NRC's Staff Requirements Memorandum for SECY-92-223, dated September 18, 1992 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML003763736), the Commission decided not to apply the final GDC to plants with construction permits issued prior to May 21, 1971. At the time of promulgation of Appendix A to 10 CFR Part 50, the Commission stressed that the final GDC were not new requirements and were promulgated to more clearly articulate the licensing requirements and practice in effect at that time. Each plant, licensed before the final GDC were formally adopted, was evaluated on a plant-specific basis, determined to be safe, and licensed by the Commission.

The licensees for PBAPS, Units 2 and 3, have made changes to the facility over the life of the plant that may have invoked the final GDC. The extent to which the final GDC have been invoked can be found in specific sections of the UFSAR and in other plant-specific design and licensing basis documentation.

Design Features

The normal heat sink for PBAPS is the Conowingo Pond. The Conowingo Pond is a reservoir on the Susquehanna River formed by the Conowingo Dam (located approximately 8.5 miles downstream of the PBAPS site) and the Holtwood Dam (located approximately 6 miles upstream of the PBAPS site). The normal heat sink supplies cooling water to the non-safety-related Circulating Water system and the non-safety-related Service Water system. The normal heat sink also supplies the cooling water for the safety-related high-pressure service water (HPSW) system and the safety-related emergency service water (ESW) system.

The PBAPS design includes an emergency heat sink, which provides heat removal capability for safe reactor shutdown in the event the normal heat sink (Conowingo Pond) is unavailable due to flooding or loss of the Conowingo Dam. The emergency heat sink consists of three mechanical-draft cooling towers with an integral water storage reservoir.

Previous Power Uprates

The AEC issued full power operating licenses for PBAPS, Units 2 and 3, on October 25, 1973, and July 2, 1974, respectively. Both units were licensed at an original licensed thermal power level (OLTP) of 3293 MWt.

By Amendment Nos. 198 and 211 (Units 2 and 3, respectively) dated October 18, 1994, and July 18, 1995, the NRC approved an approximate 5 percent stretch power uprate that authorized an increase in the maximum thermal power level from 3293 MWt to 3458 MWt.

By Amendment Nos. 247 and 250 (Units 2 and 3, respectively) both dated November 22, 2002, the NRC approved a 1.62 percent measurement uncertainty recapture (MUR) uprate that authorized an increase in the maximum thermal power level from 3458 MWt to the CLTP level of 3514 MWt.

The proposed EPU power level of 3951 MWt represents an increase of approximately 20 percent above the OLTP level of 3293 MWt and an increase of approximately 12.4 percent above the CLTP level of 3514 MWt. In terms of gross output, the proposed EPU represents an increase of approximately 140 megawatts electric (MWe) over the current gross output for each unit.

1.3 Licensee's Approach

The licensee submitted the PBAPS, Units 2 and 3, application for an EPU license amendment request (LAR) by letter dated September 28, 2012 (Reference 1). The September 28, 2012, application is referred to in this safety evaluation (SE) as "the EPU LAR."

As discussed in Section 2.1 of Attachment 1 to the EPU LAR, the application was prepared following the guidelines contained in NRC-approved General Electric (GE) Licensing Topical Report (LTR) NEDC-33004P-A, "Constant Pressure Power Uprate," (Reference 20). The constant pressure power uprate (CPPU) LTR is commonly referred to as the "CLTR."

The evaluation methods and conclusions of the CLTR were approved for GE fuel up through GE14 fuel assemblies. The PBAPS, Units 2 and 3 cores at the time of EPU implementation are expected to consist only of GNF2 fuel. As such, certain evaluations and conclusions of the CLTR are not applicable for fuel design-dependent evaluations supporting the PBAPS EPU. For fuel-dependent topics, the PBAPS application used the guidance in NRC-approved GE LTRs NEDC-32424P-A, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate" (Reference 21), and NEDC-32523P-A, "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate," (Reference 22). These two LTRs are commonly referred to as "ELTR1" and "ELTR2," respectively.

Attachment 6 to the EPU LAR contains GE-Hitachi Nuclear Energy Americas LLC (GEH) report NEDC-33566P, "Safety Analysis Report for Exelon Peach Bottom Atomic Power Station Units 2 and 3 Constant Pressure Power Uprate." This report, referred to as the power uprate safety analysis report (PUSAR), summarizes the results of evaluations performed by GEH to justify the PBAPS EPU. Attachment 6 is a proprietary (i.e., non-public) version of the PUSAR. A non-proprietary (i.e., public) version of the PUSAR is contained in Attachment 4 to the EPU LAR.

For issues which have been evaluated generically, the PUSAR references the NRC-approved generic evaluations in the CLTR, ELTR1, or ELTR2. PUSAR Section 2, "Safety Evaluation," is presented in a format consistent with the BWR template SE contained in Section 3.2 of the NRC's Office of Nuclear Reactor Regulation's (NRR's) Review Standard (RS)-001, "Review Standard for Extended Power Uprates" (Reference 23). The regulatory evaluation sections in the PUSAR, have been modified from those shown in RS-001 in order to reflect the PBAPS design and licensing basis.

As described in Section 1.2 of the PUSAR, an increase in the electrical output of a BWR is accomplished primarily by generation and supply of higher steam flow to the turbine-generator. Most BWRs, as originally licensed, have as-designed equipment and system capability to accommodate steam flow rates at least 5% above the original rating. In addition, continuing improvements in the analytical techniques have resulted in a significant increase in the design and operating margin between the calculated safety analyses results and the current plant licensing limits. The available margins in the calculated results, combined with the as-designed excess equipment, system, and component capabilities: (1) have allowed many BWRs to increase their thermal power ratings by 5% without any nuclear steam supply system (NSSS) hardware modifications; and (2) provide for power increases up to 20% with some non-safety hardware modifications.

For PBAPS, the method for achieving higher steam flow necessary for the proposed EPU would be accomplished by retaining the existing maximum extended load line limit analysis (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 (Reference 1, Attachment 4, page 1-13). As discussed in Section 2.8.2.1 of the PUSAR, the additional energy requirements for EPU are met by an increase in 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.

As discussed in Section 1.2 of the PUSAR, the proposed approach would not increase the maximum normal operating reactor vessel dome pressure or the current licensed maximum core flow. EPU operation would not involve increasing the maximum reactor vessel dome pressure because the plant, due to modifications to non-safety power generation equipment, would have sufficient pressure control and turbine flow capabilities to control the inlet pressure conditions at the turbine. Table 1-2 of the PUSAR provides a summary of the reactor thermal-hydraulic parameters for CLTP plant operating conditions and the proposed EPU conditions (Reference 1, Attachment 4, page 1-12).

As discussed in Attachment 1 to the EPU LAR, following implementation of the EPU, the leading edge flow meter (LEFM) will remain the primary system used to measure feedwater flow and provide input to the core thermal power calculation. The licensee also stated that the proposed maximum authorized power level of 3951 MWt at EPU will no longer take credit for the reduced uncertainty of the LEFM previously gained through analysis (i.e., analysis associated with the MUR uprate amendment discussed in SE Section 1.2 above).

The licensee plans to implement the EPU in one step. As discussed in the cover letter for the Supplement 27 to the EPU LAR (Reference 116), once approved, the licensee plans to fully implement the amendment prior to startup from refueling outage P2R20 for Unit 2, which is currently scheduled for completion in December 2014. For Unit 3, the licensee plans to fully implement the amendment prior to startup from refueling outage P3R20, which is currently scheduled for completion in October 2015. Subsequent to the above referenced refueling outages, the respective plants would be operated at the EPU power level (i.e., starting in Cycle 21).

1.4 Plant Modifications

The licensee has determined that plant modifications are necessary to implement the proposed EPU. A detailed discussion of the modifications is provided in Attachments 9 and 17 to the EPU LAR. The following is a summary of these modifications:

Addition of a Main Steam Spring Safety Valve (SV)

The licensee plans to install one additional main steam spring SV on each unit. The addition of a third spring SV per unit is required in order to achieve acceptable margin for the anticipated transient without scram (ATWS) event analysis at EPU conditions.

Standby Liquid Control (SLC) System Modifications

The licensee plans the following SLC system design basis analytical and procedure changes: (1) increasing the Boron-10 (B-10) enrichment; (2) increasing the SLC system pump flow rate; and (3) increasing the minimum liquid level in the SLC system.

Replacement Steam Dryers

The licensee plans to replace the existing PBAPS original equipment manufacturer steam dryers with Westinghouse designed and manufactured Nordic steam dryers. The Westinghouse steam dryer design is colloquially referred to as a "Nordic Dryer," since it was installed in 8 units in Sweden and Finland (i.e., Nordic region).

Containment Accident Pressure Credit Elimination

Currently, the PBAPS emergency core cooling system (ECCS) pumps require containment accident pressure (CAP) credit to provide adequate net positive suction head (NPSH) margin. The increased decay heat generated at EPU power levels will increase suppression pool temperatures and further decrease NPSH margin for the ECCS pumps. Rather than proposing an increased reliance on CAP credit, the licensee has decided to make plant modifications and apply methodology changes that will increase NPSH margin for these pumps to the extent that reliance on CAP can be eliminated. The modifications include: (1) a residual heat removal (RHR) system heat exchanger cross-tie modification; (2) HPSW system cross-tie modification; and (3) condensate storage tank (CST) modifications.

High Pressure (HP) Turbine

Two HP turbines (one per Unit) will be modified or replaced. The HP turbine retrofit is necessary due to capacity limitations on the current HP turbine and the main turbine control system.

Condenser

Atmospheric relief diaphragms were added to allow for adequate pressure relief to protect the condenser at EPU conditions.

Turbine Cross Around Relief Valves (CARVs)

All 12 CARVs (six per unit) will have setpoints adjusted for EPU operating conditions. There are no physical changes to the valves as the CARVs have sufficient capacity for operation at EPU conditions.

Reactor Feed Pump Turbines (RFPTs)

All six RFPTs (three per unit) are scheduled to be modified. The turbine retrofit is needed to accommodate the higher blade stresses at EPU conditions.

Feedwater Heaters (FWHs)

Five of the FWHs will be replaced for the EPU.

Reactor Water Clean Up (RWCU)

The RWCU system is sized to maintain an equilibrium contamination level in the reactor. For EPU, feedwater flow increases while the RWCU system flow will remain the same. This challenges reactor chemistry. To counteract the reduction in margin, the efficiency of the RWCU system will be improved. This modification will install flow diffusers on all four (two per unit) RWCU demineralizers. The flow diffusers increase the efficiency of the RWCU demineralizers, thereby minimizing the impact of increased FW flow on reactor water chemistry.

Flow Induced Vibration Accelerometers

The Main Steam and Feedwater systems, as well as portions of the Condensate, Extraction Steam and Heater Drain systems, will become susceptible to increased vibrations at EPU conditions as a result of higher flow rates. A confirmatory test program will be implemented to monitor piping and attached component vibration levels on these systems during initial power ascension to EPU conditions. Piping in the drywell and inaccessible piping outside containment will be monitored using accelerometers at select locations on the piping and attached components.

Condensate Pumps/Motors

All six (three per unit) condensate pumps and motors will be upgraded. The pump upgrade will change the impellers of the condensate pump. The condensate motor will be replaced with a larger motor to support the pump upgrade. The upgrades will increase the pump head at EPU flow rates.

Condensate Filter/Demineralizer

Four (two per unit) additional condensate demineralizers will be installed. The additional demineralizers will increase the condensate demineralizer flow capacity by approximately 20 percent.

Main Steam Pipe Support Modifications

Main steam system pipe support modifications will be made to accommodate the revised loadings due to EPU.

Reactor Pressure Vessel Internals

The design requirement for the minimum number of shroud head bolts has increased for EPU from 29 to 32. The additional shroud head bolts will be installed in 2014 for Unit 2, and in 2015 for Unit 3.

Hydrogen Chemistry/Noble Chemistry

The hydrogen, oxygen and zinc injection systems will be modified. The majority of the modifications include setpoint and control point adjustments to accommodate higher flow rates. In addition to the system setpoint changes, the oxygen injection valve will have the valve trim changed to accommodate the increase in the oxygen flow rate.

Generator and Auxiliaries

Both main generators will be modified for EPU. Unit 2 will have a rewound rotor and Unit 3 will have a new rotor. In addition, the generator auxiliaries will be modified or retrofitted to accommodate the new generator rating. The modification to the generators and auxiliaries will allow the units to operate at a higher million volt amp (MVA) output.

Iso-phase Bus Duct (IPBD)

The IPBD will be modified to support the main generator electrical output increase. The modification will require replacement of several portions of the existing IPBD.

Plant Instrumentation & Controls Update

EPU operating conditions require rescaling and setpoint changes of affected instruments in various plant systems. EPU operating conditions also reduce margin for some instruments and some of these will also require rescaling to gain back that margin. Instrument changes include tuning the parameters for feedwater control and the display ranges for the Safety Parameter Display system. Thermowells and probes in the feedwater, condensate and main steam systems will be reviewed for structural integrity and will be replaced as necessary.

Recirculation Pump Trip Timing

The EPU ATWS analysis requires a faster coast down of the recirculation pumps, reducing reactor power faster. This will be accomplished by the relocation of the ATWS-Recirculation Pump Trip (RPT) from the motor-generator sets to the recirculation pump motor breaker.

Motor-Operated Valves (MOVs)

The MOVs affected by the post loss-of-coolant accident (LOCA) drywell and wetwell pressure changes due to EPU were evaluated for change in differential pressure. Of these MOVs, eight have a negative margin impact and will be modified prior to implementation of the EPU. An additional five MOVs were identified to have changed from medium to low margin and will be modified to return them to high acceptable margin.

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

1.5 Method of NRC Staff Review

The NRC's staff's review of the PBAPS EPU application is based on NRC Review Standard RS-001, "Review Standard for Extended Power Uprates," (Reference 23). RS-001 contains guidance for evaluating each area of review in the application, including the specific GDC used as the NRC's acceptance criteria. Since the guidance and template SE contained in RS-001 is based on the final GDC and PBAPS, Units 2 and 3, were designed and constructed based on the draft GDC, Exelon submitted a supplement to the EPU application dated February 15, 2013 (Reference 2), which provided a revision to the template SE in RS-001. The revised SE template replaced references to the final GDC with the corresponding design criteria that constitute the current licensing basis for PBAPS. In preparing this SE, the NRC staff used the template SE provided by the licensee with minor modifications, as needed, to reflect the applicable guidance used by the staff in the review.

The NRC staff reviewed the licensee's application to ensure that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner; (2) activities proposed will be conducted in compliance with the Commission's regulations; and (3) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public. The purpose of the NRC staff's review is to evaluate the licensee's assessment of the impact of the proposed EPU on design-basis analyses. The NRC staff evaluated the licensee's application and supplements. The NRC staff also performed audits of analyses supporting the EPU and performed confirmatory calculations 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 EPU, the NRC staff reviewed relevant material to ensure that the licensee/contractor used the methods consistent with the limitations and restrictions placed on the methods. In addition, the NRC staff considered the effects of the changes in plant operating conditions on the use of these methods to ensure that the methods are appropriate for use at the proposed EPU conditions. Details of the NRC staff's review are provided in Section 2.0 of this SE.

Audits of analyses supporting the EPU were conducted in relation to the following topics:

- Replacement steam dryer structural integrity (see SE Section 2.2.6)
- Review of long-term stability and ATWS scenarios (see SE Sections 2.8.3.2 and 2.8.5.7)

Independent confirmatory calculations were performed by the NRC staff in relation to the following topics:

- pressure-temperature limits and upper-shelf energy (see SE Section 2.1.2)
- fuel system design (see SE Section 2.8.1)
- radiological consequences (see Section 2.9.2)

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 primarily focused on the effects of the proposed EPU on the licensee's reactor vessel surveillance capsule withdrawal schedule. The NRC's acceptance criteria are based on: (1) final General Design Criterion (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 rapidly propagating fracture; (2) final GDC-31, insofar as it requires that the RCPB be designed with margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; (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 are contained in Standard Review Plan (SRP) Section 5.3.1 and other guidance provided in Matrix 1 of RS-001.

As an alternative to a plant surveillance program implemented consistent with American Society for Testing and Materials (ASTM) E185, "Standard Practice for Design of Surveillance Programs for Light-Water Moderated Nuclear Power Reactor Vessels," Appendix H to 10 CFR Part 50 allows for 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 reactors that have similar design and operating features."

Technical Evaluation

The licensee discussed the impact of the proposed EPU on the reactor pressure vessel (RPV) material surveillance program, which is part of the Boiling Water Reactor Vessel and Internals Program (BWRVIP) ISP, in Section 2.1.1 of the PUSAR. The fluence estimate for the EPU is lower than the original CLTP estimate due to the licensee swapping from a dosimetry-based calculation method to a theoretical fluence calculation using an NRC-approved methodology. The use of theoretical fluence calculations is standard and is likely to enhance the comparability of PBAPS to other plants when fluence is a factor.

The licensee stated that the PBAPS RPV surveillance program consists of three capsules in each unit. One capsule containing Charpy specimens was removed from the Unit 2 and 3 vessels after Cycle 7, and were reconstituted and reinserted after testing during Refueling Outage 8 (2R08 and 3R08 for Units 2 and 3, respectively). Unit 2 is a representative host capsule in the ISP, for which a second capsule is scheduled to be removed at 30 effective full-power years (EFPY). All other capsules currently in place at PBAPS are not currently scheduled for removal. The licensee stated that the effects of the EPU would have no impact on the existing surveillance schedule.

BWRVIP-86, Revision 1, "BWR Vessel and Internals Project, Updated BWR Integrated Surveillance Program (ISP) Implementation Plan," dated September 2008 (Reference 24), establishes the ISP requirements for RPV base and weld metal in all operating BWRs for the first 40-year operating period and for the first 20-year period of extended operation. The NRC's final SE for BWRVIP-86, Revision 1, dated October 2011 (Reference 25), confirms that the ISP requirements are compliant with the ISP requirements established in Appendix H to 10 CFR Part 50. The ISP provides for a number of surveillance capsules to be removed from specified BWRs and to be available for testing during the license renewal period for the BWR fleet. The ISP establishes acceptable technical criteria for capsule withdrawal and testing. The NRC staff questioned whether the proposed EPU will impact the licensee's effective implementation of the BWRVIP ISP. The licensee responded, in Attachment 8 to Supplement 3 to the EPU LAR (Reference 4), that the EPU will not adversely impact the effective implementation of the BWRVIP ISP and that the appropriate BWRVIP personnel were notified of the EPU request. The ISP program materials at PBAPS will be appropriately handled and/or bounded by capsule materials found in other plants. Therefore, the NRC staff concludes that the licensee's RPV material surveillance program for PBAPS, Units 2 and 3, will remain in compliance with the requirements specified in Appendix H to 10 CFR Part 50 under EPU conditions.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed 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 final GDC-14 and final GDC-31 in this respect following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the reactor vessel material surveillance program.

2.1.2 Pressure-Temperature Limits and Upper-Shelf Energy

Regulatory Evaluation

Appendix G of 10 CFR Part 50 provides fracture toughness requirements for ferritic materials in the RCPB, including requirements on the upper-shelf energy (USE) values used for assessing the safety margins of the reactor vessel materials against ductile tearing and requirements for calculating pressure-temperature (P-T) limits for the plant. These P-T limits are established to ensure the structural integrity of the ferritic components of the RCPB during any condition of normal operation, including anticipated operational occurrences and hydrostatic tests. The NRC staff's review of P-T limits covered the P-T limits methodology and the calculations for the number of EFPY specified for the proposed EPU, considering neutron embrittlement effects and using linear elastic fracture mechanics. The NRC's acceptance criteria for P-T limits are based on: (1) final 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) final GDC-31, insofar as it requires that the RCPB be designed with margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; (3) 10 CFR Part 50, Appendix G, which specifies fracture toughness requirements for ferritic components of the RCPB; and (4) 10 CFR 50.60, which requires compliance with the requirements of 10 CFR Part 50, Appendix G. Specific review criteria are contained in SRP Section 5.3.2 and other guidance provided in Matrix 1 of RS-001.

Technical Evaluation

USE Calculations

The requirements in Appendix G to 10 CFR Part 50 provide the NRC staff's criteria for maintaining acceptable levels of USE for the RPV beltline materials of operating reactors throughout the licensed operational lives of the facilities. The rule requires RPV beltline materials to have a minimum USE value of 75 foot-pounds (ft-lb) initially (i.e., in the unirradiated condition) and to maintain a minimum USE value above 50 ft-lb throughout the life of the RPV, unless it is demonstrated in a manner, approved by the NRC, that lower values of USE would provide margins of safety against fracture equivalent to those required by Appendix G of the American Society of Mechanical Engineers (ASME) *Boiler and Pressure Vessel Code* (Code), Section XI. The rule also requires that the methods used to calculate USE values must account for the effects of neutron radiation on the USE values for the materials and must incorporate any relevant RPV surveillance capsule data that are reported through implementation of a plant's Appendix H to 10 CFR Part 50 RPV materials surveillance program. The NRC staff's recommended guidelines for calculating the effects of neutron radiation on the USE values for the RPV beltline materials are specified in NRC Regulatory Guide (RG) 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," dated May 1988 (Reference 26).

Projected USE values for RPV materials are calculated based on the projected neutron fluence at a postulated flaw depth at a location of one-quarter of the vessel wall thickness from the clad/base metal interface of the RPV (1/4T), weight percentage (wt. %) copper (Cu) in the material, and the initial USE value for the material prior to exposure to neutron radiation. Initial USE values are unavailable for PBAPS, Units 2 and 3, beltlines. Therefore, projected USE values were generated by the licensee via an equivalent margin analysis (EMA) documented in NEDO-32205-A, Revision 1 (Reference 27) to determine compliance with the USE requirements of 10 CFR Part 50, Appendix G. The USE EMA was later updated via BWRVIP-74 (Reference 28), which was reviewed and approved by the NRC staff in 2001 (Reference 29).

The licensee provided ISP surveillance results for the limiting welds and plates in PBAPS, Units 2 and 3. In addition, the licensee calculated the projected 1/4T USE decrease at 54 EFPY, and compared this decrease with the appropriate conditions set forth in BWRVIP-74. The NRC staff performed the USE decrease calculations and found the licensee's calculations to be correct. The NRC staff further confirmed that the licensee properly implemented the EMA conditions on USE decrease in compliance with BWRVIP-74 and the related NRC staff SE. Therefore, the NRC staff concludes that the PBAPS, Units 2 and 3 RPV beltline materials will maintain sufficient USE for 54 EFPY.

P-T Limits 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 limits obtained by following the methods of analysis and the margins of safety of the ASME Code, Section XI, Appendix G. The rule also requires that the P-T limits calculations account for the effects of neutron radiation on the material properties of the RPV beltline materials and that P-T limits calculations incorporate any relevant RPV surveillance capsule data that are reported as part of the licensee's implementation of its 10 CFR Part 50, Appendix H, RPV materials surveillance program. The NRC staff's recommended guidelines for calculating the effects of neutron radiation on the adjusted reference temperature (ART) values used for P-T limits calculations are specified in RG 1.99, Revision 2.

The licensee stated that the current P-T limits remain bounding for EPU conditions including consideration of the N-16 water level instrumentation nozzle. The current ART values for the beltline plates and welds likewise remain bounding for EPU conditions due to the conservative fluence previously considered. The NRC staff independently confirmed that the provided ART values and their inputs and calculation were appropriately reported and calculated in Tables 2.1-1a through 2.1-2b of the PUSAR. This verification included calculation of predicted USE decrease, verification of reported material chemistries, and calculation of ART values. In particular, the NRC staff verified that the bounding materials for PBAPS, Units 2 and 3, Heat C2873-1 and Heat C2773-2 respectively, remain the bounding materials. The NRC staff calculated that the bounding materials 1/4T ART values of 64.0 °F and 88.6 °F, respectively, remain bounded by those used in the current P-T limits and those previously submitted in the PBAPS license renewal application where they reported to be 70 °F and 97 °F (Reference 30). The P-T limits based on the lower bounding ART values are due to a reduced estimate of fluence stemming from the implementation of NRC-approved theoretical fluence calculation methods. As increasing fluence results in stricter P-T limits, the reduction of estimated fluence increases the conservatism of the existing P-T limits. Consequently, the existing P-T limits based on higher fluences bound EPU conditions.

RPV Circumferential and Axial Welds

The ASME Code, Section XI, Table IWB-2500-1 requires inspection of all RPV welds at regular intervals. On June 15, 2000, the NRC granted relief from performing the ASME Code, Section XI-required examinations of the PBAPS, Units 2 and 3, RPV circumferential welds for the original 40-year licensed operating period, under pre-EPU operating conditions (Reference 31). The basis for this relief was the Electric Power Research Institute (EPRI) Boiling Water Reactor Vessel and Internals Project (BWRVIP) BWRVIP-05 report, "BWR Reactor Pressure Vessel Shell Weld Inspection Recommendation," which was approved by the NRC staff in an SE dated July 28, 1998 (Reference 32). The BWRVIP-05 report concluded that the conditional failure probabilities for BWR RPV circumferential welds are orders of magnitude lower than those of the axial shell welds. The NRC evaluated the BWRVIP-05 report and allowed licensees to use it as a technical basis for requesting relief from circumferential shell weld examinations, provided the licensee demonstrates that its plant-specific RPV circumferential shell weld parameters are bounded by those in the BWRVIP-05 report. The PBAPS, Units 2 and 3, RPV circumferential weld parameters, prior to EPU operating conditions, are bounded by the BWRVIP-05 report and this was the basis for granting relief to the licensee from performing volumetric examinations of the RPV circumferential welds for the remainder of the original 40-year license period.

The NRC staff's SE provides a limiting conditional failure probability of 1.78×10^{-5} per reactor year for a limiting plant-specific mean RT_{NDT} of 70.6 °F for Chicago Bridge and Ironworks (CB&I) fabricated RPVs at 64 EFPY. The NRC staff confirmed that the mean RT_{NDT} of the circumferential welds at PBAPS, Unit 2 and 3, are projected to be 4.4 °F and 6.8 °F, respectively, at the end of the current license; the same as the licensee's values. In this evaluation, the chemistry factor, ΔRT_{NDT}, and mean RT_{NDT} were calculated consistently with the guidelines of RG 1.99, Revision 2. The calculated value of mean RT_{NDT} for the circumferential welds at PBAPS, Units 2 and 3, are significantly lower than that for the limiting plant-specific case for CB&I-fabricated RPVs, indicating that the conditional failure probability of the PBAPS, Units 2 and 3, circumferential welds are much less than 1.78×10^{-5} per reactor year. Based on the above, the NRC staff concludes that the PBAPS, Units 2 and 3, RPV circumferential weld parameters will continue to be bounded by the BWRVIP-05 parameters discussed above under EPU conditions (Reference 34).

Additionally, the NRC staff requested that the licensee confirm that the operator training and procedures to limit the frequency of cold over-pressure events implemented consistent with Generic Letter 98-05, "Boiling Water Reactor Licensees Use of the BWRVIP-05 Report to Request Relief from Augmented Examination Requirements on Reactor Pressure Vessel Circumferential Shell Welds," dated November 10, 1998 (ADAMS Accession No. ML031110082), would remain in place post-EPU. In Attachment 8 to Supplement 3 to the EPU LAR (Reference 4), the licensee confirmed that the training and procedures would remain in place post-EPU and during the period of extended operation; would not be adversely affected by the EPU; and would remain adequate for EPU operating conditions.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the USE, P-T limits, and RPV circumferential weld properties. The NRC staff concludes that the licensee has adequately addressed the impact of the EPU on the USE, P-T limits, and RPV circumferential weld properties. Specifically, the NRC staff concludes that: (1) the PBAPS, Units 2 and 3, RPV beltline materials will remain acceptable, with respect to the USE, under EPU conditions, through 54 EFPY; (2) the licensee has addressed the impact of the EPU on the ART values and the P-T limits for the RPV beltline materials; and (3) the RPV circumferential weld properties will remain bounded by the NRC failure probability analysis from Appendix A to BWRVIP-05 under EPU conditions through 54 EFPY. Based on the above, the NRC staff concludes that PBAPS, Units 2 and 3, will continue to meet the requirements of Appendices G and H to 10 CFR Part 50, and 10 CFR 50.60, and will enable the licensee to comply with final GDC-14 and final GDC- 31 in this respect following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the USE, P-T limits, and RPV circumferential weld properties.

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 draft GDC-1 and 10 CFR 50.55a for material specifications, controls on welding, and inspection of reactor internals and core supports. Specific review criteria are contained in SRP Section 4.5.2 and BWRVIP-26.

Technical Evaluation

The licensee discussed the impact of the EPU on the PBAPS, Units 2 and 3, reactor vessel internals (RVI) components in Section 2.1.3 of the PUSAR. The licensee assessed the RVI components and found them acceptable for continued operation through the end of the currently licensed period of operation (54 EFPY) under EPU conditions.

The licensee's RVI and core support materials evaluation addressed the materials specifications, mechanical properties, welds, weld controls, nondestructive examination procedures, corrosion resistance, and susceptibility to degradation of the RVI and core supports. The licensee's RVI and core support materials evaluation indicated that the RVI and core support materials will continue to be acceptable under EPU conditions and will continue to meet the requirements of the current licensing basis (CLB) and 10 CFR 50.55a.

The licensee discussed the potential for irradiation-assisted stress-corrosion cracking (IASCC) in RVI and core support components. The licensee stated that the increased neutron fluence resulting from the EPU can create the potential for additional IASCC susceptibility in these components. To address this potential, the licensee has a procedurally-controlled program for the augmented nondestructive examination of selected RVI components in order to ensure their continued structural integrity. The inspection techniques utilized are primarily for the detection and characterization of service-induced, surface-connected planar discontinuities, such as intergranular stress-corrosion cracking (IGSCC) and IASCC in welds and adjacent base materials.

Components selected for inspection include those that are identified as susceptible to in-service degradation, and augmented examination is conducted for verification of structural integrity. These components have been identified through the review of NRC Inspection and Enforcement Bulletins, BWRVIP documents, and recommendations provided by General Electric Service Information Letters. The inspection program provides performance frequency for nondestructive examination and associated acceptance criteria. Components inspected include the following:

1. Core spray (CS) piping
2. Core plate
3. CS spargers
4. Core shroud and core shroud support
5. Jet pumps and associated components
6. Top guide
7. Lower plenum
8. Vessel inside diameter attachment welds
9. Instrumentation penetrations
10. Feedwater spargers
11. In-core flux monitoring guide tubes
12. Control rod guide tubes

The licensee stated that neutron fluence calculations, performed at EPU conditions, indicate that three components (top guide, core shroud, and core plate) will exceed the 5×10^{20} neutrons per square centimeter (n/cm^2) (E > 1 million electron volts (MeV)) neutron fluence threshold value for IASCC susceptibility at 54 EFPY. The licensee has implemented the BWRVIP-augmented inspection program for RVI components at PBAPS, Units 2 and 3. The licensee has specified that the following inspection programs were used to manage the effects of IASCC:

- Top Guide (BWRVIP-26-A) (Reference 33)
- Shroud (BWRVIP-76-A) (Reference 34)
- Core Plate (BWRVIP-25) (Reference 35)

Top guide inspections requirements are specified in BWRVIP-26-A, "BWR Top Guide Inspection and Flaw Evaluation Guidelines," but the NRC staff has previously noted that BWRVIP-26-A is insufficient to address the potential for cracking multiple top guide beams. In Attachment 8 to Supplement 3 to the EPU LAR (Reference 4), the licensee confirmed that BWRVIP-183, "Top Guide Grid Beam Inspection and Flaw Evaluation Guidelines" (Reference 36), has been implemented providing sufficient inspection to address this issue and noted that top guide grid cracking has not been observed in inspections conducted to date at PBAPS, Units 2 and 3. In addition to the inspections outlined above, PBAPS, Units 2 and 3, utilizes hydrogen water chemistry to mitigate the potential for IGSCC and IASCC in RVI components. The licensee confirmed that water chemistry conditions are maintained consistent with the EPRI and established industry guidelines, specifically BWRVIP-190, "BWR Water Chemistry Guidelines," 2008 Revision (Reference 37). In addition, noble metal chemical addition was implemented at PBAPS, Units 2 and 3, and is used in conjunction with hydrogen water chemistry.

Regarding BWRVIP-25, the NRC staff inquired as to whether wedges had been installed, an analysis of the core plate bolts had been conducted, or if BWRVIP-25 compliant inspections were being conducted. The licensee responded that wedges had not been installed and that an analysis of the core plate bolts had been performed. This analysis indicated that the minimum number of core plate bolts required to maintain functionality was only 18 out of the total of 34 core plate bolts at each unit. Furthermore, the licensee confirmed that VT-3 sampling inspections were being conducted as an alternative to the BWRVIP-25 required inspections. These inspections have been implemented as an interim strategy until December 31, 2015, or until the NRC approves the revised BWRVIP guidance for core plate bolts. The NRC staff finds that the core plate bolt analysis supplemented by VT-3 inspection is acceptable with regards to the proposed EPU.

Based on the above, the NRC staff concludes that the licensee performed an adequate assessment of the RVI components under EPU conditions and that the licensee's implementation of the BWRVIP programs, for inspection and flaw evaluation of the RVI components, will ensure that the effects of aging are adequately managed under EPU conditions at PBAPS, Units 2 and 3. Implementation of the inspection program, described above, provides reasonable assurance of the timely identification of any degradation of RVI components after implementation of the EPU. In addition, water chemistry additions help mitigate potential IGSCC and IASCC in RVI components. The NRC staff concludes that the licensee's continued adherence to BWRVIP guidance, in addition to mitigating programs, will continue to maintain an acceptable course of action for managing the susceptibility to degradation in the PBAPS, Units 2 and 3, RVI components under EPU conditions.

Conclusion

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

2.1.4 Reactor Coolant Pressure Boundary Materials

Regulatory Evaluation

The RCPB defines the boundary of systems and components containing the high-pressure fluids produced in the reactor. The NRC staff's review of RCPB materials covered its specifications, compatibility with the reactor coolant, fabrication and processing, susceptibility to degradation, and degradation management programs. The NRC's acceptance criteria for

RCPB materials are based on: (1) 10 CFR 50.55a and draft GDC-1, insofar as they require that those systems and components which are essential to the prevention of accidents which could affect the public health and safety or to mitigation of their consequences be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed; (2) final 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; (3) final GDC-31, insofar as it requires that the RCPB be designed with margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; and (4) 10 CFR Part 50, Appendix G, which specifies fracture toughness requirements for ferritic components of the RCPB. Specific review criteria are contained in SRP Section 5.2.3 and other guidance provided in Matrix 1 of RS-001. Additional review guidance for IGSCC is contained in NRC Generic Letter 88-01, "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping," dated January 25, 1988, and NUREG-0313, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping," dated August 12, 1977, as modified by BWRVIP 75-A, "Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules," October 1999. Additional review guidance for thermal embrittlement of cast austenitic stainless steel components is contained in a letter from the NRC to the Nuclear Energy Institute (NEI), dated May 19, 2000.

Technical Evaluation

This technical evaluation considers the effect of the changes in plant operating conditions due to the proposed EPU on identified and potential modes of degradation to the materials of construction of the RCPB (in this case piping and nozzles). Degradation modes are considered generically and may or may not specifically apply to the proposed EPU for PBAPS. Changes in operating conditions are specific to the plant. For the purposes of this evaluation, identified modes of degradation are those described in the NUREG-1801, Revision 2, "Generic Aging Lessons Learned (GALL) Report" (Reference 38). These include IGSCC of stainless steel, thermal aging of stainless steel, and irradiation effects including cracking of all materials. While flow-accelerated corrosion and fatigue meet the current definition of "identified" degradation modes, they are not addressed here but are considered specifically elsewhere in this SE. "Potential" modes of degradation are generally not considered in the GALL Report because the degradation mode is less common or the presence of the material is less likely. Potential modes of degradation, which will be considered here, include IGSCC of nickel alloys, transgranular cracking of stainless steel, and loss of material (general corrosion) of stainless steel and nickel alloys. Current plant operating conditions, as well as proposed operating conditions following the EPU, are contained in Table 1-2 of the PUSAR. This table indicates that, as a result of the proposed EPU, there will be: a) no change in maximum nominal reactor dome pressure (i.e., maximum pressure will remain at 1050 pounds per square inch (psi) following the EPU); b) no change in maximum nominal reactor dome temperature (i.e., maximum temperature will remain at 550.5 °F following the EPU); and c) there will be a significant change in the reactor vessel steam flow rate (i.e., steam flow will increase from 14.387 million pounds per hour (Mlb/hr) to 16.171 Mlb/hr). The NRC staff notes that, while peak temperatures in the system do not change, changes in flow rate will cause minor changes in downstream temperatures. The implication of these minor changes will be discussed below.

Identified Modes of Degradation - IGSCC of Stainless Steel

Both initiation and growth of IGSCC are thermally-dependent processes. As temperature increases, time to initiation decreases and crack growth rate increases. The NRC is unaware of any data which would indicate that the occurrence of IGSCC in rapidly flowing systems is a function of the flow rate. Cracking may be a function of flow rate under essentially stagnant conditions.

The occurrence of IGSCC in stainless steel material is well documented and has been the subject of numerous NRC and industry publications. Reasonable assurance that stainless steel components in the RCPB will not fail to meet their intended safety functions due to IGSCC is provided through an inspection program contained the ASME Code, Section XI and augmented by BWRVIP 75-A (Reference 39). This inspection program depends on the precise materials of construction of the component under consideration, whether crack mitigation techniques have been employed and whether normal or hydrogen water chemistry is in use. System temperature is not a criterion which is considered in the inspection program.

Given that system temperature is not a variable considered in ASME Section XI/BWRVIP 75-A for establishing inspection frequency, and given that the inspection intervals established in ASME Section XI/BWRVIP 75-A have been effective in providing reasonable assurance that the intended functions of the RCPB materials will be maintained, the NRC staff finds that the inspection program contained in ASME Section XI/BWRVIP 75-A is effective for the maximum system temperature which exists at the plant prior to the proposed EPU. Given that the maximum system temperature will not increase as a result of the proposed EPU, the staff finds that the inspection program outlined in ASME Section XI/BWRVIP 75-A will be adequate following the implementation of the EPU. Given that the inspection program contained in ASME Section XI/BWRVIP 75-A is adequate for peak system temperatures, it is also adequate for all lower temperatures because cracks will initiate and grow more slowly under lower temperature conditions. The staff is, therefore, unconcerned about any minor variations in downstream temperatures, because the maximum temperature associated with these variations must still be less than the maximum system temperature and, therefore, the necessary inspection interval will be bounded by the intervals contained in ASME Section XI/BWRVIP 75-A. The licensee has added additional conservatism to its inspection program by following the more rigorous inspection program identified in BWRVIP 75-A for use with normal water chemistry despite the fact that the plant employs hydrogen water chemistry in conjunction with the on-line noble metal catalyst injection (On-Line NobleChem™ process).

Identified Modes of Degradation - Thermal Aging of Stainless Steel

Some cast austenitic stainless steels are subject to thermal aging. Thermal aging manifests itself as an increase in hardness and yield strength and a decrease in ductility and toughness. The degree of aging is a function of the chemistry of the steel and the process by which it was cast. The rate of degradation is a function of the operating temperature of the material.

Given that the licensee has not indicated that cast stainless steel components will be replaced as a result of the proposed EPU, and given that the changes to the operating environment caused by the EPU do not affect either the rate (no temperature change) or the extent (no change in the metallurgical chemistry of the component) of thermal aging, the NRC staff has no concern regarding this material degradation mode as a result of the EPU.

Identified Modes of Degradation - Irradiation Effects, Including Cracking, of all Materials

Irradiation effects, including IASCC, swelling, and embrittlement are possible in all materials used in the RCPB. The threshold for IASCC is generally considered to be approximately 5×10^{20} n/cm^2. The licensee indicated that, as a result of the proposed EPU, there would be some increase in neutron fluence. Based on the fluence projected for the EPU conditions and an operating life of 54 EFPY, the licensee identified three components (the top guide, the shroud, and the core plate) which are expected to exceed the IASCC threshold. The NRC staff notes that no pressure boundary components have been identified that will exceed the IASCC threshold and, as a result, the staff has no concern regarding this material degradation mode to RCPB components as a result of the EPU.

Potential Modes of Degradation - IGSCC of Nickel Alloys

Although far less common than IGSCC of stainless steels, IGSCC of nickel alloys is well documented. Just as in the case of IGSCC of stainless steels, IGSCC of nickel alloys is temperature sensitive. Increases in temperature decrease the time to crack initiation and increase the crack growth rate. Also, in a manner similar to stainless steel, inspection programs (ASME Section XI and BWRVIP 75-A) for nickel alloy components and welds have been effective in providing reasonable assurance that these welds and components will maintain their intended safety functions at the maximum temperature within the system prior to the proposed EPU. Given that there is no increase in maximum system temperature associated with the EPU, the new operating conditions remain bounded by the existing conditions, upon which the current, successful, inspection program is based. As was the case with stainless steel components, the NRC staff has no concern regarding the minor temperature variation between the existing and EPU conditions, irrespective of whether these variations are positive or negative, because the temperatures must be less than the maximum system temperature and, therefore, bounded by the conditions upon which current inspections are based.

Potential Modes of Degradation - Transgranular Cracking of Stainless Steel

Transgranular stress-corrosion cracking is a possible degradation mechanism for austenitic stainless steels when exposed to environments containing halogens, such as chlorides, and dissolved oxygen. The NRC staff notes that EPRI water chemistry guidelines recommend that the levels of oxygen and halogens be maintained at levels which will not result in transgranular cracking. Based on the licensee's current adherence to the EPRI water chemistry guidelines and the lack of any proposed modification to the plant's oxygen or chloride levels as a result of the proposed EPU, the NRC staff has no concern regarding this material degradation mode as a result of the EPU.

Potential Modes of Degradation - Loss of Material (General Corrosion) Stainless Steel and Nickel Alloys

General corrosion is often, but not always, a positive function of temperature (i.e., corrosion rates increase as temperature increases). General corrosion is also, under certain circumstances, a function of flow rate (i.e., when the rate of corrosion is limited by mass transport). With respect to the proposed EPU, the corrosion rates of stainless steels and nickel alloys when exposed to high purity reactor coolant are sufficiently low so as not to require consideration. Changes in environment associated with the EPU are not sufficient to cause these materials to corrode at an appreciable rate.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the susceptibility of RCPB materials to known degradation mechanisms and concludes that the licensee has identified appropriate degradation management programs to address the effects of changes in system operating temperature on the integrity of RCPB materials. The NRC staff further concludes that the licensee has demonstrated that the RCPB materials will continue to be acceptable following implementation of the proposed EPU and will continue to meet the requirements of final GDC14, final GDC 31, draft GDC 1, 10 CFR Part 50, Appendix G, and 10 CFR 50.55a. Therefore, the NRC staff finds the proposed EPU acceptable with respect to RCPB materials.

2.1.5 Protective Coating Systems (Paints) - Organic Materials

Regulatory Evaluation

Protective coating systems (paints) provide a means for protecting the surfaces of facilities and equipment from corrosion and radionuclide contamination. Coatings also provide wear protection during plant operation and maintenance activities. Considering temperature, radiation and pressure, the NRC staff's review covered Service Level 1 protective coating systems used inside the containment for their suitability and stability under design basis loss-of-coolant accident (DBLOCA) conditions. The NRC's acceptance criteria for protective coating systems are based on: (1) 10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," which covers quality assurance requirements for the design, fabrication, and construction of safety-related SSCs; and (2) RG 1.54, Revision 2, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants," which covers application and performance monitoring of coatings in nuclear power plants. Specific review criteria are contained in SRP Section 6.1.2.

Technical Evaluation

The licensee addressed protective coating systems in Section 2.1.5 of the PUSAR, as supplemented by information provided in Attachment 7 to Supplement 3 to the EPU LAR (Reference 4) and in Attachment 2 to Supplement 8 to the EPU LAR (Reference 9). The licensee stated that the protective systems used inside the containment were evaluated for their continued suitability for, and stability under, DBLOCA conditions. The evaluation considered radiation and chemical effects at the EPU conditions. The licensee indicated that the drywell of Units 2 and 3, and the wetwell airspace of Unit 2, are coated with Carboline Carbozinc 11 (CZ11) and topcoated with Phenoline 368 (368). The licensee further stated that CZ11 is currently the primary coating below the waterline in the Unit 2 torus and for the entire Unit 3 torus. The licensee stated that BIO-DUR 560BLUE coating is being used as a torus relining material and is design-basis accident (DBA) qualified for EPU conditions. This coating system was applied in the PBAPS Unit 2 torus in 2012, and the Unit 3 torus in 2013. The licensee stated that the coating was applied to all carbon steel surfaces 1 foot (ft) above normal water level and all areas below the water level except for the shell and ring girders which were coated from nominally 1 ft above the normal water level and below. The shell and ring girders are coated with the CZ11/368 coating system. The BIO-DUR 560BLUE coating is qualified to temperature, pressure, and radiation levels of 240 °F, 50 pounds per square inch gauge (psig), and $\geq 1 \times 10^9$ rads, respectively.

In Attachment 7 to Supplement 3 to the EPU LAR, the licensee provided information on qualification testing for all safety-related coatings in containment. The licensee stated that the CZ11/368 coating system was installed prior to the issuance of standards on DBA testing (i.e., American National Standards Institute (ANSI) N101.2-1972 and ASTM D3843); therefore, the CZ11/368 coating system at PBAPS is not a DBA-qualified coating system. Since this coating system was installed prior to the development of ANSI N101.2 and ASTM D3843, the CLB for CZ11/368 does not include a DBA qualification requirement. The NRC staff reviewed licensing basis documents (e.g., UFSAR and confirmed that the CZ11/368 coating system was installed prior to the issuance of ANSI N101.2-1972 and ASTM D3843.

The licensee stated that for those coatings that are DBA-qualified at PBAPS, it meets the requirements of the ANSI N101.2-1972 and N5.9-1967 (revised as ANSI N5.12-1974). The licensee also stated that PBAPS currently follows ASTM D3843-93 to fulfill 10 CFR Part 50, Appendix B, requirements with clarification, exception, and one additional requirement as stated in the PBAPS Quality Assurance Topical Report. The licensee stated that the clarification, exception, and one additional requirement to ASTM D3843 are as follows:

- For coating formulations developed prior to ASTM D3843, Service Level I qualification based on ANSI N5.9 (Revised as ANSI N5.12) and ANSI N101.2 remains valid.

- Inspections will be documented for record purposes as required by 10 CFR 50, Appendix B, and by the PBAPS quality assurance program description.

- Limitations on use of coatings and cleaning materials which contain elements which could contribute to corrosion, intergranular cracking, or stress-corrosion cracking of safety-related stainless steel will be followed as described in Section C.4 of Regulatory Guide 1.54, dated June 1973.

The licensee reported that the EPU conditions are not significantly different from the current operating conditions. The licensee stated that the peak drywell pressure increases from 49.5 psig to 50.4 psig at EPU conditions. The drywell temperature remains at 340 °F at EPU conditions. The peak wetwell pressure increases from 32.3 to 32.4 psig at EPU conditions. The peak wetwell temperature increases from 175 to 181 °F at EPU conditions. The post-accident drywell dose rates increase from 1.87×10^8 to 2.14×10^8 rads at EPU conditions. The post-accident suppression pool chamber dose rates increase from 3.30×10^7 to 3.77×10^7 rads at EPU conditions.

In Attachment 2 to Supplement 8 to the EPU LAR, the licensee provided information on the last two periodic assessments of the CZ11/368 coating system. For the PBAPS, Unit 2, coating assessment, the licensee stated that in 2012 no degradation of the CZ11/368 coating was identified which required remediation or repair; therefore, no degraded material was added to the unqualified coatings log (UCL). During the 2010 coating assessment at PBAPS, Unit 2, a minor amount of degraded material was identified amounting to 0.007 lbs. of CZ11/368 being added to the UCL. The licensee reported that the total amount of unqualified coating is tracked and documented in the Unit 2 UCL. Similarly, the licensee reported that in 2007 and 2009, an assessment was performed on the Unit 3 CZ11/368 coating system and it was stated that no additional degradation was added to the UCL and no remediation or repair was identified. As with Unit 2, the coating material in Unit 3 is tracked and documented in the Unit 3 UCL. In consideration of the above information, the NRC staff has reasonable assurance that the CZ11/368 coating system will withstand the proposed EPU conditions because: (1) the results of the Units 2 and 3 last two coating assessments supports the continued suitability of the coating in performing its intended function; (2) the staff notes that the CZ11/368 coating system has been DBA-qualified at EPU conditions comparable to that of PBAPS at other similarly operated plants; and (3) the EPU conditions will not be significantly different from current operating conditions.

The NRC staff has reviewed the licensee's evaluation and the PBAPS UFSAR, and has confirmed that the applicable regulatory guidance was followed. The staff has reasonable assurance that the coatings will not be adversely impacted by the EPU and that temperature, pressure, and radiation limits remain acceptable for EPU operation.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on protective coating systems. The staff concludes that the licensee has appropriately addressed the impact of changes in conditions following a DBLOCA and their effects on the protective coatings. The staff further concludes that the licensee has demonstrated that there is reasonable assurance that the protective coatings will continue to perform its design function following implementation of the proposed EPU. Specifically, the protective coatings will continue to meet the requirements of 10 CFR Part 50, Appendix B, and the guidance in RG 1.54. Therefore, the NRC staff finds the proposed EPU acceptable with respect to protective coatings systems.

2.1.6 Flow-Accelerated Corrosion

Regulatory Evaluation

Flow-accelerated corrosion (FAC) is a corrosion mechanism that occurs in carbon steel components exposed to single-phase or two-phase water flow. Components made from stainless steel are immune to FAC, and FAC is significantly reduced in components containing even small amounts of chromium or molybdenum. The rates of material loss due to FAC depend on the system flow velocity, component geometry, fluid temperature, steam quality, oxygen content, and pH. During plant operation, it is not normally possible to maintain all of these parameters in a regime that minimizes FAC; therefore, loss of material by FAC can occur. The NRC staff reviewed the effects of the proposed EPU on FAC and the adequacy of the licensee's FAC program to predict the rate of material loss so that repair or replacement of damaged components could be made before reaching a critical thickness. 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 licensee addressed FAC in Section 2.1.6 of the PUSAR. The licensee stated that the PBAPS FAC program is based on:

- NUREG-1344, "Erosion/Corrosion-Induced Pipe Wall Thinning in U.S. Nuclear Power Plants" (Reference 40);
- NRC Bulletin No. 87-01, "Thinning of Pipe Walls in Nuclear Power Plants" (Reference 41);
- NRC Generic Letter 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning" (Reference 42); and
- EPRI Report NSAC-202L, Revision 3, "Recommendations for an Effective Flow-Accelerated Corrosion Program" (Reference 43).

The licensee stated that the proposed EPU implementation will affect system water and steam flow rates, temperatures, enthalpies, and dissolved oxygen concentration. These factors are instrumental in impacting FAC susceptibility and wear rates. The licensee indicated that as a result of EPU operating conditions, some lines will experience accelerated rates of FAC, while others will have reduced rates. In any event, it was stated that lines that were not previously susceptible to FAC will not become susceptible to FAC at EPU operating conditions.

The licensee stated that the PBAPS FAC program monitors FAC susceptible piping to ensure the structural integrity and functionality are maintained. The scope of the program includes small and large bore piping systems. In addition, the FAC program consists of predicting material loss by the use of the CHECWORKS™ Steam/Feedwater Application computer code, visual inspection, and volumetric examination of susceptible systems.

The licensee indicated that components selected for inspection are determined by utilizing the CHECWORKS™ predictive model to 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 available before reaching minimum wall thickness. Inputs to the model include plant operating parameters, component material and design features, and inspection results. Additionally, the PBAPS FAC program utilizes industry experience, PBAPS experience, and the engineering judgment of the plant engineers to determine inspection sites.

The licensee stated that the PBAPS CHECWORKS™ predictive model was updated to reflect plant operating conditions at EPU temperatures, pressures, and velocities. Additionally, the licensee provided tables comparing the wear rate of FAC susceptible components before and after implementation of the proposed EPU. The tables also provided expected values for temperature, velocity, oxygen, and quality parameters for EPU operating conditions. The maximum corrosion rate increase predicted due to the proposed operating conditions was 56.3%, located in the feedwater heater 5 drain line to heater 4. The NRC staff finds the predicted corrosion rate increase reasonable for the corresponding changes in operating conditions. Additionally, the licensee provided a sample list of components for which wall thinning was predicted and measured by ultrasonic testing, or another approved method, to provide a comparison between actual wall thickness of a component and the predicted wall thickness by the CHECWORKS™ program. The staff reviewed the data and finds that the CHECWORKS™ program provides an adequate correlation between predicted wall thickness and measured wall thickness, and that there is reasonable assurance that the program will continue to be an acceptable predictive model after the implementation of the EPU.

In addition to FAC, the licensee stated that PBAPS inspects certain components for degradation caused by liquid droplet impingement and cavitation. The licensee indicated that liquid droplet impingement is determined by evaluating leaks in valves where conditions may cause velocities of two-phase mixtures to increase dramatically. The licensee reported that the FAC program inspects for cavitation per system engineering requests.

The NRC staff finds that the current FAC program incorporates conservatism to ensure that components susceptible to FAC are managed appropriately prior to exceeding minimum wall thickness. In addition, the staff finds the inclusion of inspection and monitoring for other degradation mechanisms such as liquid droplet impingement and cavitation acceptable because these mechanisms affect many of the same systems susceptible to FAC. The staff finds that the updated FAC program, with the incorporated system changes resulting from the EPU, will provide reasonable assurance that components susceptible to FAC will be managed appropriately post-EPU implementation.

Conclusion

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

2.1.7 Reactor Water Cleanup System

Regulatory Evaluation

The reactor water cleanup (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 NRC's acceptance criteria for the RWCU system are based on: (1) draft GDC-9 and 34, insofar as they require that the RCPB be designed and constructed so as to have an exceedingly low probability of RCPB gross rupture or significant leakage; (2) final GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents; and (3) draft GDC 51, insofar as it requires that systems that may contain radioactivity be designed with appropriate confinement. Specific review criteria are contained in SRP Section 5.4.8.

Technical Evaluation

The licensee addressed the RWCU system in Section 2.1.7 of the PUSAR. The licensee stated that the RWCU system will operate at a slightly decreased temperature (from 530 °F to 527.5 °F) at the proposed EPU operating conditions. The RWCU system flow is usually selected to be approximately 1% of feedwater flow; however, the licensee stated that the RWCU system was analyzed for flow at 147,000 pounds mass (lbm)/hour (hr) at EPU conditions. This flow rate is approximately 0.89% of feedwater flow. The licensee considered water chemistry, heat exchanger performance, pump performance, flow control valve capability and filter/demineralizer performance in the evaluation of RWCU performance. The licensee stated that the RWCU system analysis concludes that:

1. An increase in filter/demineralizer backwash frequency occurs, it was indicated that this is within the capacity of the radwaste system.

2. Changes in operating system conditions result from a decrease in inlet temperature and an increase in feedwater system operating pressure.

3. RWCU system filter/demineralizer control valves will operate in a more open position to compensate for the increased RWCU system pressure associated with the increase in feedwater system pressure.

4. It was indicated that no changes to instrumentation are required, and setpoint changes are not required due to the system process parameter changes.

The licensee stated that, due to the increase in feedwater flow, there is expected to be increases in three key reactor coolant chemistry parameters. The licensee indicated that sulfate concentrations will increase from 0.82 parts per billion (ppb) to 0.95 ppb. This value is below the administrative limit of 2.0 ppb for sulfates. The chlorides concentration is expected to increase from 0.38 ppb to 0.44 ppb. This value is below the administrative limit of 1.0 ppb for chlorides. The reactor water conductivity is expected to increase from 0.131 micro siemens per centimeter squared ($\mu S/cm^2$) to 0.143 $\mu S/cm^2$. This value is below the administrative limit of 0.150 $\mu S/cm^2$ for conductivity. The NRC staff has reviewed the estimated increase in these parameters and has determined that there is sufficient operating margin remaining before parameter administrative limits are challenged under the proposed EPU conditions.

The NRC staff has reviewed the licensee's evaluation and considers that the proposed EPU will only introduce minor changes in the RWCU system operating parameters, which will not affect satisfactory performance of its intended functions.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the RWCU system and concludes that the licensee has adequately addressed changes due to the EPU and is effect on the RWCU system. The NRC staff further concludes that the licensee has demonstrated that the RWCU system will continue to be acceptable following implementation of the proposed EPU and will continue to meet the requirements of final GDC-60, and draft GDCs 9, 34 and 51. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the 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 inservice inspection (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 draft GDC-40 and 42 insofar as they require that protection be provided for engineered safety features (ESFs) against the dynamic effects that might result from plant equipment failures. Specific review criteria are contained in SRP Section 3.6.2.

Technical Evaluation

The licensee's review of the effects of the proposed EPU on the postulated pipe rupture locations and associated dynamic effects for PBAPS is documented in PUSAR Section 2.2.1, which follows the CPPU approach of the NRC-approved CLTR. The CLB evaluation criteria for high-energy line breaks (HELBs) are contained in PBAPS UFSAR Appendix A, Subsection A.10, "High Energy Pipe Break Outside the Primary Containment." Subsection A.10 is in response to the AEC's December 1972 letter on the subject of high energy piping system failure outside the primary containment.

Review of the PUSAR and the licensee's responses to NRC staff's request for additional information (RAI) (Reference 13) show that the majority of the RCPB piping systems experience no increase in pressure, temperature, flow or mechanical loadings for CPPU. This is also consistent with BWR EPUs which the staff has previously reviewed and approved. The licensee found that the only high energy piping systems affected by the EPU are main steam (MS), feedwater (FW) and reactor water cleanup (RWCU).

In its PUSAR and in its response to the staff's RAI, the licensee showed that it evaluated the affected piping systems, identified above at EPU conditions and found that no new break or crack locations need to be postulated due to EPU. By its review, the NRC staff found the licensee's evaluations acceptable because the evaluations were conducted in accordance with

NRC-approved methodology and the current plant licensing and design basis, without making changes to the implementation of the existing criteria for defining pipe break and crack locations.

Steam Line High-Energy Line Breaks (HELBs)

The licensee reconstituted the pipe stress analysis for the main steam piping system due the increased loads in the MS piping resulting from the turbine stop valve closure (TSVC) transient at higher EPU flow rates. By its evaluations and by using current licensing basis criteria for defining pipe break and crack locations, the licensee found that no new break or crack locations are required to be postulated as a result of the increased piping stresses associated with the EPU.

Section 10.1 of the NRC-approved CLTR states that "[[

]]" The licensee reviewed heat balances produced for the proposed EPU and confirmed that steam conditions are unaffected at postulated break location of the MS, the normally pressurized steam supply to the high-pressure coolant injection (HPCI) turbine and the normally pressurized steam supply to the reactor core isolation cooling (RCIC) turbine.

Based on the CLTR and the licensee's evaluations, which showed that there are no new postulated break or crack locations required for EPU and that steam conditions remain unaffected at pipe break postulated location of steam lines, the NRC staff concurs with the licensee that the EPU has no effect on the mass and energy (M&E) releases from a HELB in a steam line.

Liquid Line HELBs

According to the CLTR, CPPU may increase subcooling in the reactor vessel, which may lead to increased break flow rates for liquid line breaks. The licensee identified that the increase in vessel subcooling could affect the RWCU line break analysis. In addition, operation at EPU conditions requires an increase in the MS and FW flows, which results in an increase in FW system pressures. The licensee noted that this increase in pressure may lead to increased break flow rates for liquid line breaks in the RWCU and FW systems. The licensee re-evaluated the HELB M&E releases at EPU conditions for the RWCU and FW systems as described below.

RWCU System Line Breaks

The licensee, while reviewing the HELB analyses for EPU, found the CLB RWCU analysis contained an error. To correct the error, the RWCU HELB was reanalyzed to incorporate M&E releases that bound both CLTP and EPU conditions. The licensee's responses to the staff's RAIs (References 13 and 19) show that the new compartment peak pressures from the revised analyses are greater than the compartment peak pressures in the analysis of record. The licensee evaluated the revised compartment peak pressures for the affected rooms to access their structural capability to withstand the increased compartment pressures. The evaluation concluded that no structural failures or penetration seal failures will result from the increase in calculated peak compartment pressures from the M&E releases at postulated RWCU line breaks at EPU conditions. Based on the information provided by the licensee, the NRC staff finds that the effects of the increases in compartment pressures at EPU conditions are acceptable.

FW System Line Breaks

The licensee identified that the FW system operating piping temperatures and pressures will increase slightly due to EPU. Higher FW operating pressures result from the higher head loss associated with a higher FW flow rate. FW temperature, for operation at 102% of EPU thermal power, increases by 2 °F. The licensee indicated that the associated minor changes in FW line break M&E releases are still bounded by the current MS line break M&E releases, which remain unchanged by the EPU (see above). The licensee found that the effects of a FW system line break on MS tunnel peak pressures and temperatures are bounded by a MS line break in the MS tunnel and stated that, for the portion of the smaller RWCU piping attached to the FW piping in the MS tunnel, M&E releases from breaks in the smaller RWCU piping are bounded by the FW break M&E releases.

In addition, the licensee found that the small increases in EPU operating temperature and pressure are bounded by the design temperature and pressure used in the existing piping analyses, which remain valid at EPU conditions. Therefore, the NRC staff concurs with the licensee that no new FW break locations are required to be postulated for EPU. The staff notes that since no new FW breaks are postulated for EPU and the M&E releases at existing FW postulated breaks are bounded by M&E releases of the MS line postulated breaks, it is reasonable to conclude that the EPU has no effect on the M&E releases from a HELB in the FW piping.

For further review of the evaluations of the effects of postulated pipe breaks, including that of M&E releases at pipe break locations, see SE Sections 2.5.1.3 and 2.6.

Pipe Whip and Jet Impingement

The NRC staff notes that pipe whip and jet impingement loads resulting from HELBs are directly proportional to system pressure, pipe break area, and jet coefficients (for jet thrust loads) for saturated steam, saturated water, steam/water mixture and for non-flashing subcooled water. As mentioned above, the CLTR states that, "[[
]]" In addition, according to the licensee's evaluations, there are no new steam pipe break locations postulated due to EPU. Therefore, pressure and break area have not changed for postulated steam breaks at EPU conditions. Hence, the NRC staff notes that it is reasonable to conclude that the proposed EPU has no effect on steam line breaks pipe whip and jet impingement loads.

The licensee has evaluated the effect of increased FW and RWCU system pressures for pipe whip and jet impingement and by its review has determined that the EPU FW and RWCU pipe whip and jet impingement loads are bounded by the current analysis of record for pipe whip and jet impingement loads. Therefore, the proposed EPU has no effect on FW and RWCU line breaks pipe whip and jet impingement loads. As such, the NRC staff finds the proposed EPU acceptable with respect pipe whip and jet impingement loads resulting from HELBs.

Summary

Based on its review above, the NRC staff finds that the licensee has provided reasonable assurance that appropriate protection exists for SSCs important to safety against postulated pipe failures and their associated dynamic effects at EPU conditions.

Conclusion

The NRC staff has reviewed the licensee's evaluations related to determinations of rupture locations and associated dynamic effects and concludes that the licensee has adequately addressed the effects of the proposed EPU on them. The NRC staff further concludes that the licensee has demonstrated that SSCs important to safety will continue to meet the requirements of draft GDC 40 and 42 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 ASME *Boiler and Pressure Vessel Code* (B&PV Code), Section III, Division 1, final GDC 14 and draft GDCs 1, 2, 9, 33, 34, 40, and 42. The NRC staff's review focused on the effects of the proposed EPU on the design input parameters and the design-basis loads and load combinations for normal operating, upset, emergency, and faulted conditions. The NRC staff's review covered: (1) the analyses of flow-induced vibration; and (2) the analytical methodologies, assumptions, ASME Code editions, and computer programs used for these analyses. The NRC staff's review also included a comparison of the resulting stresses and cumulative fatigue usage factors (CUFs) against the code-allowable limits. The NRC's acceptance criteria are based on: (1) draft GDC-1, insofar as it requires that those systems and components which are essential to the prevention of accidents which could affect the public health and safety or to mitigation of their consequences be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed; (2) draft GDC-2, insofar as it requires that those systems and components which are essential to the prevention of accidents which could affect the public health and safety or to mitigation of their consequences be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions; (3) draft GDC-40 and 42, insofar as they require that protection be provided for ESFs against the dynamic effects that might result from plant equipment failures, as well as the effects of a loss-of-coolant accident (LOCA); (4) draft GDC-9 and 33, insofar as they require that the RCPB be designed and constructed so as to have an exceedingly low probability of RCPB gross rupture or significant leakage; (5) draft GDC-34 insofar as it requires that the RCPB be designed to minimize the probability of rapidly propagating type failures; and (6) final 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. 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

Reactor Coolant Pressure Boundary (RCPB) 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, residual heat removal (RHR) low pressure coolant injection (LPCI) lines, core spray (CS) injection lines, standby liquid control (SLC) system injection line, reactor pressure vessel (RPV) bottom head drain line, MS piping and MS Drain, FW piping, the RPV head vent line and safety relief valve (SRV) discharge piping. In addition, the licensee addressed branch lines, piping supports, nozzles, penetrations, flanged, and valve connections in its evaluations. The licensee also evaluated the safety-related thermowells in the MS and FW systems and the sample probe in the FW system for flow-induced vibration (FIV) due to increased flows in the MS and FW systems resulting from EPU implementation. Section 2.2.2 of the PUSAR indicates that the licensee followed the guidance from the NRC-approved CLTR (Reference 20) and that the proposed EPU for PBAPS meets all CLTR dispositions.

The PUSAR indicates that loadings which would affect stresses on piping systems and loads on pipe supports due to pressures, temperatures, flows and mechanical loads do not increase or change at EPU conditions for most of the RCPB piping systems. This assessment is consistent with the CLTR. In addition, seismic loads are not affected by EPUs and the licensee has determined that the SRV discharge loads are also not affected by the proposed EPU. The NRC staff finds this acceptable, as it compares well with CPPUs that the staff has previously reviewed and approved. The licensee reviewed the RRS system, CRD system, LPCI lines, CS injection lines, SLC system injection line, and the RPV bottom head drain line in accordance with the CLTR and [[ ]] As such, the licensee concluded these systems were acceptable for operation at the EPU conditions. The NRC staff finds the licensee's justification [[ ]] presented in Section 2.2.2 of the PUSAR acceptable, as it follows the CLTR approach and because parameters affecting the structural integrity of these piping sections have shown [[ ]]

According to the CLTR, piping loads for most of the piping systems inside containment (RCPB piping) with the exception of FW and main steam line (MSL) piping will not increase due to EPU. With regard to FW piping the licensee indicated that design-basis loads used in the current CLTP analysis of record bound piping loads at EPU conditions. Therefore, the FW piping remains structurally adequate at EPU conditions.

For the EPU, a third spring safety valve (SSV) per unit is required to be added to the "C" MSL in order to achieve acceptable margin for the ATWS analysis for EPU operation, as discussed in Attachment 9 to the EPU LAR. Therefore, the licensee performed a new plant-specific analysis for the MS and associated branch piping which included the new SSV and loading from the TSVC transient at EPU conditions. The CLTP analysis of record for the MSL did not include loads due to the TSVC transient. This transient is considered one of the most significant loads in the qualification of MS piping and supports for EPU. As discussed in PUSAR Section 2.2.2.2.1.2, TSVC loads bound the main steam isolation valve (MSIV) closure event loads because the MSIV closure time is significantly longer than the TSV closure time. Also for CPPU, the SRVs set point pressures do not change and, therefore, SRV actuation loads remain unchanged for the proposed EPU. According to the licensee's response to a staff RAI (Reference 13), the results of the MSL reanalysis showed that new supports are required to maintain the MSL piping stresses within design-basis limits without modifying the MS piping. In addition, modifications to existing pipe supports are required due to the increased loads at these supports. Therefore, prior to the EPU implementation, for the MS piping inside containment, the licensee is planning to install four new snubbers per unit, replace four snubbers on Unit 2 and two snubbers on Unit 3, modify the setting of one snubber on Unit 3 to accommodate for thermal movement, replace three spring can hangers per unit to accommodate seismic movement, and replace a pipe clamp with a U-bolt on one spring can hanger per unit. In addition, structural work is required for 12 existing supports per unit, which is also planned prior to the EPU implementation. The licensee analyzed each existing, modified and new pipe support to meet design-basis stress and load allowable values.

The licensee in its PUSAR, and in Supplements 12 and 18 to the EPU LAR (References 13 and 19), submitted maximum pipe stress summaries and stress summaries at critical piping locations, including RPV nozzle locations, SRV inlet locations and primary containment penetration locations. In these summaries, the licensee compared the calculated values to code allowable values. The calculated stresses exceeded the original code of construction (Power Piping USAS B31.1.0-1967) and design-basis code (ANSI B31.1-1973) allowable values for carbon steel (CS) pipe A106 Gr B at four locations inside containment. These locations are on the MS branch lines to the SRVs. The maximum exceedance shown is 12.9%. The licensee qualified these locations by utilizing a later year code edition, ASME/ANSI B31.1- 2004 with 2005 Addenda, for which it has performed a formal reconciliation report in accordance with ASME Section XI IWA-4300. The licensee in its responses to NRC staff RAIs (References 13 and 19), stated that the code reconciliation specifically evaluated the higher allowable stress values based upon the reduction in design factor from 4.0 to 3.5 as allowed by the ASME Committees and incorporated into ASME/ANSI B31.1-2005-Addenda. This reduction in design factor allows for a 14% increase in CS material allowable values. The exceedance in the original code of construction allowable values at these locations is less than 14% and, therefore, the NRC staff determined that the exceedance is acceptable in accordance with the ASME/ANSI B31.1-2005-Addenda reconciled code. In its response to the staff's RAIs (References 13 and 19), the licensee stated that the methods utilized for the revised MS piping analyses and pipe support designs are consistent with the current PBAPS design basis, which includes code reconciliations to later than code of construction code editions for piping analysis and pipe support design, and which are documented and controlled by Exelon in accordance with the Exelon Quality Assurance (QA) plan and procedures. The licensee's response also shows that the TSVC transient loads are included in the piping load case load combinations for upset, emergency and faulted conditions in accordance to the PBAPS design basis for load case combinations. The NRC staff finds the licensee's evaluation of the inclusion of the TSVC transient loads in the piping load case load combinations for upset, emergency, and faulted conditions is acceptable since it is in accordance with the PBAPS current design basis for load case combinations.

Based on its review, as discussed above, the NRC staff finds that, after completion of planned pipe support modifications to the MS piping inside containment including its branch lines, pipe supports and associated components are structurally adequate for EPU.

The licensee [[ ]] dispositioned the MS line flow elements (restrictors) for structural integrity. The licensee's structural integrity review of the MS line flow restrictors is documented in PUSAR Section 2.5.4.1.2, "Main Steam Line Flow Restrictors," which finds that there is no effect on the structural integrity of the MS line flow restrictors due to the EPU. The NRC staff finds that the structural integrity of the MS line flow restrictors was not affected by the CPPU since the licensee's evaluation was in accordance with the staff-approved CLTR.

The licensee evaluated the FIV levels associated with the MS and FW piping systems that are projected to increase for CPPU. The NRC staff's evaluation of FIV and power ascension and testing programs for CPPU are documented in SE Sections 2.2.6 and 2.12.

The PUSAR shows tabulated evaluation stress summary results for the effects of FIV at EPU conditions on the safety-related MS and FW thermowells and the FW sample probes. The licensee, in its response to NRC staff RAIs (References 13, 19 and 78), provided discussions to justify its evaluations and revised its PUSAR table. The calculated EPU stresses due to FIV for fatigue consideration are well below the allowable values derived using guidance from the ASME Standards and Guidance for Operation and Maintenance of Nuclear Power Plants (OM-S/G) Part 3, "Requirements for Preoperational and Initial Start-up Vibration Testing of Nuclear Power Plant Piping Systems." The licensee also provided a quantitative summary of reduced velocity and reduced damping values, calculated in accordance with the guidance presented in ASME Code Section III, Appendix N, Subparagraph N-1324.1. These values demonstrate that synchronization (lock-in) of the periodic vortex shedding frequencies to the structural natural frequency of the instruments does not occur at EPU conditions. Therefore, the NRC staff concludes that the structural evaluations of the MS and FW thermowells and the FW sample probes were acceptable for EPU since the calculated stresses due to FIV for fatigue consderations are well below the allowable values derived using the guidance from the ASME OM-S/G Part 3.

NRC Regulatory Issue Summary (RIS) 2008-30, "Fatigue Analysis of Nuclear Power Plant Components," dated December 16, 2008 (ADAMS Accession No. ML083450727), identified a concern with the simplified single-stress methodology used by some license renewal applicants to perform fatigue calculations, and as input for on-line fatigue monitoring programs, in lieu of the ASME Code, Section III, Subsection NB, Subarticle NB-3200 method. The ASME Code method requires consideration of all six stress components. Because license renewal for PBAPS, Units 2 and 3, was approved by the NRC in 2003 (ADAMS Accession No. ML031150073), prior to issuance of RIS 2008-30, the staff requested the licensee to demonstrate compliance with ASME Section III when stress-based fatigue monitoring is utilized. According to the licensee's response (Reference 13), the licensee evaluated the effect of RIS 2008-30 and determined that there are no components or locations that require stress-based fatigue monitoring for the current and EPU plant conditions. The licensee stated that if future surveillance monitoring results determine that stress-based fatigue monitoring becomes required for certain components, then stress-based fatigue monitoring in accordance with ASME Code Section III, Subsection NB will be implemented for the required components or locations. The NRC staff finds the licensee's response acceptable, as it demonstrates that PBAPS, Units 2 and 3, are not impacted by RIS 2008-30, and in the event that stress-based fatigue monitoring becomes required at PBAPS, the licensee will follow the ASME Code Section III, Subsection NB criteria.

Based on its review above, the NRC staff finds that the licensee has provided reasonable assurance that the structural integrity of the RCPB piping, supports and associated components will remain structurally adequate for the proposed EPU.

Balance-of-Plant Piping, Components, and Supports

According to the CLTR, piping loads for most of the piping systems with the exception of FW and MS lines including associated branch piping will not increase due to EPU. As discussed in PUSAR Section 2.2.2.2.2.2, the following piping systems were determined to be affected by the EPU operation:

- RHR piping (RHR heat exchanger cross-tie modification)
- High-pressure service water (HPSW) piping (HPSW cross-tie modification)
- MS piping (outside containment)
- Extraction steam piping
- FW piping (outside containment)
- Condensate piping
- Moisture separator drains piping
- FW heater vents and drains piping
- Cross around relief valve (CARV) discharge piping
- Condensate demineralizer piping (condensate demineralizer modifications)

According to the PUSAR and the licensee's response to an NRC staff RAI (Reference 13), for EPU affected safety related piping and piping which is required to withstand a seismic event, EPU operating conditions are either bounded by the design temperatures and pressures used in the current analysis of record, or the licensee, by reviewing stress margins between calculated stresses and allowable limits in the analysis of record, has determined that sufficient margin exists for the stresses to remain below allowable values when considering the EPU conditions. For the FW piping, the licensee indicated that design-basis loads used in the CLTP current analysis of record bound piping loads at EPU conditions. Therefore, the FW piping remains structurally adequate at EPU conditions.

With regard to the MS piping outside containment, similar to the MS piping inside containment (see discussion above), the licensee has performed piping reanalysis to include the TSVC transient load case in the load case load combinations for upset, emergency and faulted conditions. The MS piping stress analysis outside containment was performed in accordance with the design-basis code in the analysis of record (ASME/ANSI B31.1-1973). According to the results of the piping analysis, which includes new supports, the existing MS piping needs no piping modifications. The licensee submitted tabulated pipe stress summaries at maximum stress locations and critical locations, such as the MS anchor and the turbine stop valve locations, which show that the calculated MS pipe stresses are within code-allowable stress limits and, therefore, are acceptable. New supports on the MS piping outside containment are required to maintain the stresses in the existing piping within code limits without piping modifications. Modifications to existing pipe supports are required due to the increased loads at these support locations. Therefore, for the MS piping outside containment, prior to the EPU implementation, the licensee is planning to install four new snubbers per unit (one on each of four MS line risers in MS tunnel), modify eight existing pipe whip restraints per unit (two on each of four MS lines) to be active in north-south direction, modify four existing restraints per unit (one on each of four MS lines) to take load in vertical upward direction, replace four spring can supports per unit with vertical rigid struts with clamps and end brackets, replace two snubbers per unit with higher capacity snubbers, modify four snubber support structures per unit by replacing supporting frames and/or baseplates and anchor bolts, and modify one pipe support per unit with higher strength rods. In addition, nine spring cans will be replaced on Unit 2 and eight replaced on Unit 3, along with hardware; auxiliary steel for two spring can hangers on Unit 2 and one on Unit 3 also will be modified; and one rigid support per unit will require increased weld size of end brackets. According to Reference 13, each existing, modified and new pipe support has been analyzed to meet design-basis stress allowable values and, therefore, their designs are acceptable.

In addition to the MS pipe support modifications and the addition of a third SSV, modifications for piping and pipe supports, which are either safety-related or required to withstand a seismic event that the licensee is planning to modify and install prior to EPU implementation, include the RHR heat exchanger cross-tie modification, the HPSW cross-tie modification and the CST standpipe modification. The purpose of these modifications, which are described in detail in Attachment 9 to the EPU LAR, is that they will act in combination to provide additional net positive suction head (NPSH) margin for the ECCS pumps to eliminate the need to credit containment accident pressure (CAP) for design-basis accidents (DBAs) and other analyzed events. The licensee assessed the structural integrity of these modifications in accordance with its current design basis and in its response to an NRC staff RAI (Reference 13) provided quantitative summaries of the structural analyses results, which show that these planned modifications meet design-basis structural limits and, therefore, are acceptable.

The PUSAR notes that the MS and FW piping have increased flow rates and flow velocities in order to accommodate the EPU. As a result, the MS and FW piping experience increased vibration levels, approximately proportional to the square of the flow velocities. The licensee established a piping vibration monitoring program to be implemented at PBAPS during power ascension to confirm acceptable vibration levels at EPU power. This program addresses systems impacted by EPU and identifies locations on those systems where monitoring equipment will be installed. Attachment 13 to the EPU LAR provides additional information for the EPU vibration monitoring program which, in addition to FW and MS, includes related extraction steam, condensate and heater drain systems, which also experience similar flow rate increases under EPU conditions and are included in the EPU vibration monitoring program. The vibration acceptance criteria for the licensee's power ascension program for EPU follow the guidance presented in ASME OM-S/G Part 3, guidance of which is also recommended by SRP 3.9.2, "Dynamic Testing and Analysis of Systems, Structures and Components." The licensee's EPU vibration monitoring program, which addresses systems impacted by EPU, follows ASME and NRC guidance and, therefore, is acceptable. Further review of the licensee's FIV and power ascension and testing programs for EPU are documented in SE Sections 2.2.6 and 2.12.

The NRC staff reviewed the piping stress analysis and other information provided by the licensee and finds that the licensee has adequately addressed the effects of the proposed EPU on the BOP piping, pipe components and pipe supports. Based on its review, the staff concludes that the proposed EPU does not adversely affect the structural integrity of the BOP piping, pipe components and pipe supports.

Other Piping Evaluations

The licensee also evaluated the torus-attached structures. Design-basis loss-of-coolant accident (DBLOCA) hydrodynamic loads, including the pool swell loads, vent thrust loads, condensation oscillation (CO) loads and chugging loads were originally defined and evaluated for PBAPS. The evaluation of the structures attached to the torus shell, such as piping, vent penetrations and valves are based on these bounding DBLOCA hydrodynamic loads. Because the hydrodynamic loads that include the pool swell loads, CO loads and chugging loads did not change for EPU, the NRC staff concurs with the licensee that the EPU has no adverse effects on the torus shell attached piping and valves, as identified in the PUSAR. The licensee also determined that the SRV discharge loads used in the existing analyses bound those at EPU conditions. The NRC staff also determined that the structural integrity of the discharge piping will not be affected by the proposed EPU.

In PUSAR Section 2.6.1.2.1, "Loss-of-Coolant Accident Loads," the licensee identified that the vent thrust loads at four locations exceeded the plant-specific vent thrust loads originally calculated during the Mark I containment long-term program (i.e., PBAPS analysis of record) by no greater than 2.5%. The NRC staff requested the licensee to identify these four locations and discuss how the structural integrity of the affected SSCs has been qualified for EPU. According to the licensee's response (Reference 13), these locations that exceed the analysis of record (AOR) loads are as follows:

- Vertical load on main vent cap - exceeded AOR load by 0.12%
- Horizontal load on main vent cap - exceeded AOR load by 0.05%
- Horizontal load on vent header per miter bend - exceeded AOR load by 2.46%
- Total vertical load on main vent - exceeded AOR load by 0.12%

The NRC staff's review of the licensee's response contained in Reference 13 determined that the licensee has conservatively evaluated these increases in vent thrust loads. The licensee has shown that margin to the allowable stress in the AOR of the vent system is a minimum of 13%. With the exception of the vent thrust loads, all other loads used in the AOR for the vent system remain bounding at EPU. The licensee conservatively assumed that the vent system maximum stress will increase by 2.5% (the maximum increase of vent thrust loads), even though other contributing loads remain unchanged, which is much less than the AOR margin to allowable stress of 13%. Therefore, the NRC staff concurs with the licensee that the vent system remains structurally qualified at EPU conditions since the increases in vent thrust loads were conservatively evaluated and there is significant margin to the allowable stress in the AOR for the vent system.

Reactor Vessel and Supports

The licensee evaluated the effects of the proposed EPU on 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 utilized the methodology documented in the NRC-approved power uprate LTRs (CLTR, ELTR1 and ELTR2, References 20, 21, and 22, respectively). In accordance with this methodology, the licensee compared the proposed power uprate conditions [[ ]] against those used in the current design basis evaluations [[

]]

The licensee, in accordance with the CLTR, performed [[ ]] evaluations for components [[

]] The NRC staff finds the licensee's methodology acceptable, as it is in accordance with the NRC approved power uprate LTRs and adjustments have been made to account for the 60-year plant life due to the plant renewed license.

The original code of construction for the RPV analysis is the ASME Code Section III, 1965 Edition. Vessel components that currently have a 40-year fatigue CUF [[

]] are the FW nozzle and the reactor recirculation inlet and outlet nozzles. As discussed in the PUSAR Section 2.2.2.3 and Reference 13, since original construction, all three of these nozzles have been modified as follows:

- Feedwater Nozzle: This component was modified and the governing Code for the modification is the ASME Code, Section III, 1974 Edition with Addenda to and including Summer 1976.

- Recirculation Inlet Nozzle: This component was modified and the governing Code for the modification is the ASME Code, Section III, 1989 Edition with Addenda to and including Winter 1990.

- Recirculation Outlet Nozzle Unit 3: This component was modified and the governing Code for the modification is the ASME Code, Section III, 1980 Edition with Addenda to and including Winter 1981.

For EPU, [[ ]] evaluations were performed for these components utilizing the above governing codes of record in the PBAPS licensing basis. PUSAR Table 2.2-7 contains maximum stress and fatigue evaluation summary results at EPU conditions, which show that the code of record allowable limits have been met for these components and, therefore, are acceptable for EPU.

With regard to the RPV support, the licensee's response to an NRC staff RAI (Reference 13) shows that EPU conditions did not increase structural qualification loads for the RPV supporting structure and its components, which, therefore, remain acceptable for EPU.

Based on the above NRC staff's review of the licensee's evaluations of the RPV components and supporting structure, the staff finds that the RPV and its support components will continue to maintain their structural integrity at the proposed EPU conditions because maximum stresses and fatigue usage factors of EPU-affected components remain within code allowable limits.

Control Rod Drive Mechanism

Structural integrity of the control rod drive mechanism under EPU conditions is evaluated below in SE Section 2.8.4.1.

Recirculation Pumps and Supports

As discussed above in the section titled "Reactor Coolant Pressure Boundary (RCPB) Piping, Components, and Supports," the licensee reviewed a number of systems, including the reactor recirculation system (RRS), in accordance with the CLTR and [[ ]] Specifically, parameters affecting structural integrity have shown [[ ]] As shown in PUSAR Table 1-2, the maximum full power core flow rate remains unchanged between CLTP and EPU conditions. As shown in PUSAR Table 2.2-2, [[ ]] with respect to temperature, pressure and RRS drive flow rate. The NRC staff reviewed the licensee's evaluation of the RRS and finds that the system was unaffected by the EPU since the maximum full power core flow rate [[ ]] remain unchanged and the [[ ]] between CLTP and EPU conditions. The NRC staff finds that the licensee has provided reasonable assurance that RRS system pumps and supports will remain structurally adequate 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 final GDC-14 and draft GDCs 1, 2, 9, 33, 34, 40 and 42 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. 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 flow-induced vibration for safety-related and non-safety-related reactor internal components; and (2) the analytical methodologies, assumptions, ASME Code editions, and computer programs used for these analyses. The NRC staff's review also included a comparison of the resulting stresses and CUFs against the corresponding Code-allowable limits. The NRC's acceptance criteria are based on: (1) draft GDC-1, insofar as it requires that those systems and components which are essential to the prevention of accidents which could affect the public health and safety or to mitigation of their consequences be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed; (2) draft GDC-2, insofar as it requires that those systems and components which are essential to the prevention of accidents which could affect the public health and safety or to mitigation of their consequences be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions; (3) draft GDC-40 and 42, insofar as they require that protection be provided for ESFs against the dynamic effects that might result from plant equipment failures, as well as the effects of a LOCA; and (4) draft GDC-6, insofar as it requires that the reactor core be designed with appropriate margin to assure that specified acceptable fuel design limits (SAFDLs) are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences. Specific review criteria are contained in SRP Sections 3.9.1, 3.9.2, 3.9.3, and 3.9.5; and other guidance provided in Matrix 2 of RS-001.

Technical Evaluation

The RPV internals consist of core support structure and non-core support structure components. The licensee notes that the RPV internals are not certified in accordance with the provisions of the ASME Code. However, the licensee's design-basis analyses for the RPV internals used the ASME Code criteria as guidelines. The licensee used the same guidelines to reevaluate the RPV internals for the normal, upset, emergency and faulted conditions for EPU. The loads considered in the evaluation were consistent with the existing design basis and include dead weight, reactor internal pressure differences (RIPDs), seismic loads, thermal load effects, flow loads, and acoustic and flow-induced loads due to a recirculation line break. For cases where the loads due to EPU conditions are bounded by the existing design-basis loads, no further evaluation is performed. If the loads increase due to the EPU, then the effect of the load increase is evaluated further and new stresses are determined by linearly scaling up the existing design-basis stresses in proportion to the loads. The resulting stresses are compared against the design basis code allowable values. The NRC staff finds the methodology used by the licensee acceptable, as it is consistent with the NRC-approved methodology in Appendix I of ELTR1 (Reference 21).

The licensee performed qualitative and quantitative assessments of the RPV internals. The licensee's discussion of the results of the qualitative and quantitative assessments is presented in Section 2.2.3 of the PUSAR. Summaries of maximum stress at critical locations and fatigue cumulative usage factors (CUFs) from the evaluation results for the RPV internals are summarized on PUSAR Tables 2.2-11 and 2.2-12, respectively. All stresses and CUFs are shown to be within design basis allowable limits and, therefore, are acceptable.

In June 2013, GE-Hitachi Nuclear Energy Americas LLC (GEH) issued Safety Communication (SC) 09-03, Revision 1, "Shroud Screening Criteria Reports." SC 09-03 lists PBAPS, Units 2 and Unit 3, as two of the affected plants for shroud screening criteria flaw evaluations, due to the omission of the postulated recirculation line break (RLB) loads (transient acoustic or steady state flow-induced loads) in the design basis evaluation for the shroud screening criteria reports, which could potentially result in allowable flaw lengths of shroud welds to be smaller than those provided in the shroud screening criteria reports. The postulated RLB load is a faulted condition load. The NRC staff requested the licensee to discuss whether the concerns and corrective actions recommended in SC 09-03, Revision 1, including load combinations have been properly addressed for PBAPS, Units 2 and 3. According to the licensee's response (References 13 and 19), the licensee entered the GEH SC 09-03, Revision 1, concern into the PBAPS corrective action program and evaluated its impact, including if the load combinations were properly addressed for PBAPS, Units 2 and 3. The evaluation showed that sufficient margin was present in the existing shroud evaluations to ensure that the shroud welds were acceptable for the duration of the 10-year Inservice Inspection (ISI) Program interval until the next inspections (Unit 2 10-year ISI Program interval inspections were completed in 2012; the Unit 3 inspections are currently scheduled to be performed in 2015).

The acoustic and flow-induced loads due to the postulated RLB, as discussed in SC 09-03, Revision 1, were incorporated into revised shroud weld loads for PBAPS. These revised shroud weld loads include the RIPD, acoustic loads, flow-induced loads, seismic loads and deadweight loads at EPU conditions. The licensee stated that shroud weld evaluations include these revised loads and EPU fluence were performed for Unit 2 and support the 10-year inspection interval with safety factors significantly greater than the minimum requirements. The licensee's response (References 13 and 19) shows that the Unit 2 evaluations include all applicable loads and load combinations listed in SC 09-03, Revision 1. Therefore, the NRC staff concurs with the licensee that the corrective action recommendations from SC 09-03, Revision 1, including load combinations, have been properly addressed for PBAPS Unit 2. As mentioned above, according to the corrective action program evaluation of SC 09-03, Revision 1, the Unit 3 shroud contains sufficient margin in its current evaluation to the end the current 10-year interval ending in 2015. The licensee's response shows that it is planning to perform a revised core shroud flaw evaluation similar to Unit 2 for Unit 3 in 2015. Therefore, the NRC staff finds that the licensee has properly addressed the GEH SC 09-03, Revision 1, impact and the recommended corrective actions for PBAPS Units 2 and 3.

The FIV assessment of the RPV internals for EPU is contained in PUSAR, Section 2.2.3.1. According to the Section 3.3 of the NRC staff's SE for the CLTR, when power is increased from CLTP to EPU conditions, steady-state FIV levels are expected to increase approximately in proportion to the increase in the square of the fluid velocity. The licensee evaluated the following components with regards to FIV:

- Shroud
- Shroud Head and Separator Assembly
- Jet Pumps
- FW Sparger
- Jet Pump Sensing Lines
- In-Core Guide Tubes
- Control Rod Guide Tubes (CRGTs)

- Fuel Channels
- Guide Rods
- RPV Top Head Spare Instrument Nozzle
- RPV Top Head Vent Nozzle
- RPV Head Spray Nozzle
- CS Piping and Sparger

Since the core flow remains unchanged, the licensee dispositioned components in the lower plenum and core region [[ ]] in accordance with the CLTR, as not affected by the EPU. The required vibration assessments of the RPV internals affected by the EPU are described in the CLTR. The licensee performed FIV evaluations of the EPU affected internals, in accordance with the CLTR. These evaluations used a reactor power of 4,030 MWt (102% of EPU power level) and 110% of rated core flow. The EPU FIV evaluations were based on [[ ]] The expected vibration levels for EPU were then estimated by extrapolation. Vibration amplitudes were also adjusted by the square of the increased flow velocity rate at each of the extrapolation points. These expected EPU vibration levels were then compared with established vibration acceptance limits, which limit FIV alternating stress intensity to [[ ]] for austenitic stainless steels and found to be acceptable. [[ ]] The NRC staff finds the usage of the [[ ]] to be acceptable, as it is conservative when compared to the ASME Code Section III design fatigue endurance limit for austenitic stainless steel material of 13,600 psi which is further reduced for steady-state vibration by a factor of 0.8 to 10,880 psi, following guidance of ASME OM-S/G Part 3.

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

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 draft GDCs 1, 2, 6, 40 and 42 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's staff's review included certain safety-related pumps and valves typically designated as Class 1, 2, or 3 under Section III of the ASME Code and within the scope of Section XI of the ASME Code and the ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code), as applicable. The NRC staff's review focused on the effects of the proposed EPU on the required functional performance of the valves and pumps. The review also covered any impacts that the proposed EPU may have on the licensee's motor-operated valve (MOV) program related to GL 89-10, GL 96-05, and GL 95-07. The NRC staff also evaluated the licensee's consideration of lessons learned from the MOV program and the application of those lessons learned to other safety-related power-operated valves. The NRC's acceptance criteria are based on (1): draft GDC-1, insofar as they require that those systems and components which are essential to the prevention of accidents which could affect the public health and safety or to mitigation of their consequences be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed; (2) draft GDC-38, 46, 47, 48, 59, 60, 61, 63, 64, and 65, insofar as they require that the emergency core cooling system (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) draft GDC-57, insofar as it requires that piping systems penetrating containment be designed with the capability to periodically test the operability of the isolation valves to determine if valve leakage is within acceptable limits; and (4) 10 CFR 50.55a(f), insofar as it requires that pumps and valves subject to that section must meet the inservice testing program requirements identified in that section. Specific review criteria are contained in SRP Sections 3.9.3 and 3.9.6, and other guidance provided in Matrix 2 of RS-001.

Technical Evaluation

The licensee addressed safety-related valves and pumps in Section 2.2.4 of the PUSAR, as supplemented by information provided in Attachment 6 to Supplement 3 to the EPU LAR (Reference 4).

In Section 2.2.4 of the PUSAR, the licensee summarized its evaluation of the MOVs, air-operated valves (AOVs), check valves, pressure safety relief valves, and pumps within the scope of the PBAPS Inservice Testing (IST) program for the effects of the proposed EPU on the following systems: core spray (CS) system, high-pressure coolant injection system (HPCI), reactor core isolation cooling (RCIC) system, residual heat removal (RHR) system, reactor water cleanup system, standby liquid control (SLC) system, reactor building closed cooling water system, feedwater system, feedwater pump recirculation system, standby gas treatment system, combustible gas control system, main steam (MS) system, reactor recirculation system, control rod drive hydraulic system, and various sampling, testing and instrument systems. The NRC staff has reviewed the licensee's evaluation of the impact of EPU conditions on safety-related valves and pumps at PBAPS. This review is summarized below.

In response to GL 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," dated June 28, 1989 (Reference 44), and GL 96-05, "Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves," dated September 18, 1996 (Reference 45), PBAPS established a testing and surveillance program for MOVs. The NRC's acceptance of the MOV program for PBAPS was documented in NRC Inspection Report 50-277/97-07 and 50-278/97-07 dated December 16, 1997 (Reference 47). In a letter dated November 16, 2000 (Reference 48), the NRC attached the SE for the PBAPS response to GL-96-05, and stated that PBAPS had established an acceptable program to verify periodically the design-basis capability of the safety-related MOVs. Additionally, PBAPS implemented the requirements of GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves," dated

August 17, 1995 (Reference 46), which was evaluated and accepted by the NRC in a letter dated December 28, 1998 (Reference 49).

The licensee described its evaluation of the MOVs within the scope of GL 89-10 at PBAPS for the effects of the proposed EPU, including those related to pressure locking and thermal binding as addressed in GL 95-07. The licensee's review of affected systems indicates that the existing maximum operating conditions (e.g., flow rates, pressures and temperatures) remain valid for the EPU. Therefore, no changes were identified to the design functional requirements for all GL 89-10 MOVs. The licensee has evaluated all GL 89-10 MOVs for the effects of changes in system pressures and environmental temperatures due to EPU conditions. Based on the evaluation, the licensee concluded that no MOVs or valve operators require replacement for EPU. However, in Table 2.2-14 of the PUSAR, the licensee identified a list of MOVs that have negative or low margins due to changes of containment responses under EPU conditions. The affected MOVs include RHR pump suction isolation valves MO-2-10-013A/B/D and MO-3-10-013A/B/C, RCIC torus suction block valve MO-3-13-041, and CS loop pump suction valves MO-2-14-007A/B/D and MO-3-14-007A/B/C. In Attachment 6 to Supplement 3 to the EPU LAR, the licensee noted that these affected MOVs will be modified by either replacement of motor pinion and worm shaft gear or installation of a four-rotor limit switch. Post modifications, the affected MOVs will be reevaluated in accordance with the requirements of GL 89-10 and GL 96-05 to ensure acceptable valve margins are reestablished for EPU conditions. The licensee also noted that the required valve modifications will be completed prior to EPU power ascension in the fall of 2014 and 2015. Based on the licensee's plan to complete the valve margin adjustments in 2014 and 2015, prior to operation at EPU conditions, the NRC staff concludes that there is reasonable assurance that all MOVs at PBAPS will be fully capable of performing their safety-related functions under EPU conditions. As discussed below in SE Section 5.0, "Recommended Areas for Inspection," the NRC's Office of Nuclear Reactor Regulation (NRR) is recommending that NRC Region I consider including these MOV modifications as one of the EPU inspection samples. The MOVs were also evaluated for the requirements of GL 95-07 under EPU conditions, and no new MOVs were determined to be susceptible to pressure locking or thermal binding.

The licensee noted that PBAPS has an AOV program in place to address aspects of AOV design, performance monitoring and maintenance that are necessary to provide reasonable assurance that design-basis functions will be accomplished. In Table 2.2-13 of the PUSAR, the licensee has identified a list of AOVs which are selected, set, tested and maintained in accordance with the PBAPS AOV program so that the AOVs will operate under normal, abnormal, or emergency operating design-basis conditions. Based on this information, the NRC staff determined that there is reasonable assurance that all AOVs will perform their safety-related function under EPU conditions.

The licensee also stated that the PBAPS MOV and AOV programs utilize the PBAPS Corrective Action Program to evaluate and resolve non-conforming conditions identified during program performance. Included in the program is recognition of any lessons-learned or improvements identified from operating experience. The licensee uses an administrative procedure to implement the requirements in Appendix B to 10 CFR Part 50 related to the corrective action process. The NRC staff finds that use of the corrective action process is acceptable to address consideration of lessons-learned from operating experience.

The licensee reviewed the IST program for safety-related pumps and valves at PBAPS for EPU operations, and noted that EPU has no effect on the performance characteristics and IST Program requirements for safety-related pumps and valves. The licensee's review of affected systems indicates that the existing maximum operating conditions (i.e., flow rates, pressures and temperatures) remain valid for the EPU. As such, no changes in the pump head performance are required for the affected safety-related pumps at the EPU conditions. Therefore, pump designs and IST requirements for PBAPS pumps are not affected by the EPU. However, due to EPU, the PBAPS IST Program will be revised to incorporate the following changes, as discussed in Attachment 6 to Supplement 3 to the EPU LAR:

- For the SLC system, the minimum pump discharge pressure and the minimum flow requirement will be changed.
- For the condensate storage tank, a new cross-tie valve will be added.
- For the RHR system, heat exchanger cross-tie motor-operated isolation valves and inlet control valves will be added and the RHR pump baseline flow will be revised.
- For the MS system, a new spring safety valve will be added.

The Code of Record for PBAPS is the 2001 Edition through 2003 Addenda of the ASME OM Code and its fourth 10-year IST interval began on August 15, 2008, and ends on August 14, 2018. The IST Program at PBAPS assesses the operational readiness of pumps and valves in accordance with the requirements of the ASME OM Code. On the basis that the above changes will be implemented in accordance with the PBAPS IST Program, the NRC staff finds the modifications and additions described above acceptable.

Conclusion

The NRC staff has reviewed the licensee's assessments related to the functional performance of safety-related valves and pumps and concludes that the licensee has adequately addressed the effects of the proposed EPU on safety-related pumps and valves. The NRC staff further concludes that the licensee has adequately evaluated the effects of the proposed EPU on its MOV program 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 this, the NRC staff concludes that the licensee has demonstrated that safety-related valves and pumps will continue to meet the requirements of draft GDCs 1, 38, 46, 47, 48, 57, 59, 60, 61, 63, 64, 65, and 10 CFR 50.55a(f) following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable 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) draft GDC-1, insofar as it requires that those systems and components which are essential to the prevention of accidents which could affect the public health and safety or to mitigation of their consequences be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed; (2) draft GDC-2, insofar as it requires that those systems and components which are essential to the prevention of accidents which could affect the public health and safety or mitigation of their consequences be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions; (3) 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; (4) draft GDC-40 and 42, insofar as they require that protection be provided for ESFs against the dynamic effects that might result from plant equipment failures, as well as the effects of a LOCA; (5) draft GDCs 9 and 33, insofar as they require that the RCPB be designed and constructed so as to have an exceedingly low probability of RCPB gross rupture or significant leakage; (6) draft GDC-34, insofar as it requires that the RCPB be designed to minimize the probability of rapidly propagating type failures; 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.

<u>Technical Evaluation</u>

The licensee evaluated safety-related SSCs subject to EPU conditions. Seismic loads are not affected by power uprates. The licensee stated in Section 2.2.5 of the PUSAR that quality standards related to the design, fabrication, erection, and testing of the RCPB or SSCs important to safety are not relaxed or removed as a result of the EPU and changes have not been made to the plant design bases established in consideration of the seismic and geologic characteristics of the plant site. The licensee has also considered DBLOCA conditions and other HELBs that could dynamically affect safety-related mechanical and electrical equipment and components. In Section 2.2.1 of this SE, the NRC staff's review of the licensee's evaluations showed that SSCs important to safety are adequately protected from the dynamic effects of postulated pipe failures, including pipe whip and jet impingement, at EPU conditions. As shown in Section 2.2.2 of this SE, containment hydrodynamic inertia loads due to DBLOCA and SRV discharge are not affected by the proposed EPU. As discussed in Section 2.6.1 of this SE, the NRC staff concluded that ESF SSCs inside the containment will be protected from dynamic loads under EPU conditions. As discussed in Section 2.3.1 of this SE, the NRC staff found the proposed EPU acceptable with respect to the environmental qualification of electrical equipment inside and outside of containment.

The PBAPS design and licensing basis does not require a formal mechanical equipment qualification program. As shown in Section 2.2.2 of this SE, the licensee 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 EPU. The NRC staff's review of the licensee's evaluations found that the mechanical components and component supports are adequately designed for the proposed EPU conditions. Periodic preventive maintenance and testing, investigation of causes of failures, the PBAPS Maintenance Rule Program which also incorporates industry operating experience, and the design control program provide reasonable assurance that SSCs important to safety will be capable of performing their intended functions at EPU conditions.

With regard to non-metallic components found in mechanical equipment, in its response to the NRC staff's RAI (Reference 13), the licensee stated that components with non-metallic parts that fall outside of specialized component programs such as the check valve and snubber programs are maintained through the equipment reliability program. The licensee noted that normal and accident radiation doses will increase by approximately 14% due to EPU. The licensee stated that this change in radiation dose will not impact the ability of plant programs to manage component service life for non-metallic parts that are outside of the environmental qualification program. The NRC staff finds the licensee's responses acceptable, as they provide additional assurance that the reliability of plant equipment will be maintained following implementation of the proposed EPU.

Based on its review above, the NRC staff concludes that the seismic and dynamic qualification of safety-related mechanical and electrical equipment for PBAPS is not adversely impacted by the proposed EPU.

<u>Conclusion</u>

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 draft GDCs 1, 2, 9, 33, 34, 40 and 42; 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 Area - Replacement Steam Dryer Structural Integrity

<u>Regulatory Evaluation</u>

The steam dryer is a reactor internal component and is located in the steam dome portion of the reactor pressure vessel (RPV). The function of the steam dryer is to dry the steam to very high quality, approximately 99.9% quality (or 0.1% moisture carryover), when it exits the dryer. Even though the steam dryer does not perform any safety function, it must retain its structural integrity to avoid the generation of loose parts that may adversely impact the ability of other SSCs from performing their safety functions. The NRC staff's review was focused on the effects of the proposed EPU on the qualification of the replacement steam dryers (RSDs) to withstand seismic events and the dynamic effects associated with flow induced vibration, MSL break, and turbine stop valve closure. Since the steam dryer is a safety significant component, the NRC's acceptance criteria is based on: (1) 10 CFR 50.55a and draft 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) draft 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) draft 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) draft GDCs 40 and 42, insofar as they require that protection be provided for ESFs against the dynamic effects and missiles that might result from plant equipment failures, as well as the effects of a LOCA. Specific NRC review criteria are contained in NRC SRP Sections 3.9.1, 3.9.2, 3.9.3, and 3.9.5; RG 1.20 (Reference 109), and other guidance provided in Matrix 2 of RS-001.

PBAPS Current Licensing Basis

The reactor vessel and internals are described in Sections 3.3, and 4.2 of the PBAPS UFSAR. In addition to the evaluations described in the UFSAR, systems and components were evaluated during the license renewal review. Systems and system component materials of construction, operating history, and programs used to manage aging effects were evaluated for plant license renewal and documented in NUREG-1769, "Safety Evaluation Report Related to the License Renewal of Peach Bottom Atomic Power Station, Units 2 & 3," dated February 2003 (Reference 30). The reactor internals evaluation for license renewal is discussed in Section 3.1.1 of NUREG-1769.

Technical Evaluation

Plant operation at EPU conditions can result in adverse flow effects on the main steam (MS) system, feedwater (FW) system, condensate systems and their components, and the steam dryers in BWR plants from increased system flow and the associated effects of flow-induced vibration. As described in PUSAR Section 1.2, an increase in electrical output is accomplished by generating and supplying higher steam flow to the turbine generators via the MS lines. Some plant components, such as the steam dryer, do not perform a safety function but must retain its structural integrity to avoid the generation of loose parts that might adversely impact the capability of other plant equipment to perform their safety functions. Therefore, a BWR steam dryer is a safety significant component located inside the reactor pressure vessel. The NRC staff reviewed the evaluation by Exelon of the potential adverse flow effects for the proposed EPU at PBAPS including consideration of the design input parameters and the design-basis loads and load combinations for the PBAPS steam dryer for normal operation, upset, emergency, and faulted conditions. The staff's review covered the analytical methodologies, assumptions, and computer modeling used in the evaluation of the PBAPS steam dryers, and also included a comparison of the resulting stresses against the applicable limits.

As a part of the EPU LAR, Exelon plans to replace the existing PBAPS, Unit 2, original equipment manufacturer (OEM) GE parallel vane bank steam dryer with an instrumented Westinghouse 3-ring octagonal-shaped vane bank steam dryer. The licensee also plans to replace the existing PBAPS, Unit 3, OEM GE parallel vane bank steam dryer with a Westinghouse 3-ring octagonal-shaped vane bank steam dryer.

The NRC staff's review for the RSDs focused on potential adverse flow effects due to increased flow at EPU operation in order to assure the structural integrity of the RSDs under EPU conditions. The staff's detailed technical evaluation is provided below.

2.2.6.1 Background

The RSDs will be supported on four brackets attached to the inside wall surface of the reactor pressure vessel. The brackets support the dryer via its support ring. Attached under the support ring is a skirt, which has eight vertical drain channels welded to its inside. At the top of the steam dryer, there are three concentric octagons, each containing eight vane banks. The function of the vane banks is to separate the moisture from the steam flow by letting the steam pass through vertical corrugated plates placed inside the vane banks. Each vane bank has a hood that leads the steam flow into the vane bank. The vane banks stand on troughs (U-shaped channels) that collect and lead the excess water through the girder drain channels and out to the vertical drain channels. A perforated plate is mounted on the inlet side of each vane bank. This ensures an even flow through the vane banks in order to minimize the moisture carryover (MCO) to the main steam system. On top of the vane bank octagons is a web of girders welded to the vane banks for radial support.

The RSD evaluations submitted by the licensee in September 2012 were based on the Acoustic Circuit Model (ACM) 4.1 methodology, benchmarked against [[ ]] In October 2013, the licensee discovered an error in benchmarking and use of ACM 4.1 for PBAPS. Subsequently, in November 2013, the licensee decided not to use ACM 4.1 and instead reanalyzed the RSD with the Acoustic Circuit Model Enhanced (ACE) 2.0 and ACE 2.0+SPM (skirt protection model) methodology. ACE 2.0 is benchmarked against the [[ ]] of the Monticello Nuclear Generating Plant (MNGP) RSD, a Westinghouse octagonal dryer, which is consistent in design style with the proposed PBAPS RSDs. ACE 2.0+SPM is benchmarked against the [[ ]]

2.2.6.2 Plant Modifications

The licensee has determined that several plant modifications are necessary to implement the proposed EPU. Specific to the steam dryer, the licensee elected to replace the original GE parallel vane bank type slanted hood steam dryer with a 3-ring octagonal shaped vane bank steam dryer of Westinghouse design for PBAPS, Units 2 and 3. MNGP was the first plant in the United States to utilize a steam dryer of Westinghouse design, replacing the original steam dryer of GE design in 2011. PBAPS will be the second plant in the United States to use a steam dryer of Westinghouse design for Units 2 and 3. As part of the EPU implementation, an additional safety valve (Dresser safety valve) will be added in the dead-ended leg of the blind flanged stand pipe in MSL C. In November 2013, a minor design modification was also made to the RSD [[ ]]

2.2.6.3 Method of NRC Staff Review

The purpose of the NRC staff's review is to evaluate the licensee's assessment of the impact of the proposed EPU on the structural integrity of the RSDs. The staff evaluated the licensee's application and supplements. The NRC staff also utilized the experience and lessons-learned related to the steam dryers from the previous BWR EPU reviews. In addition, the staff evaluated information provided during audits at Westinghouse's Rockville, Maryland office. The results of the audits are discussed below.

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

2.2.6.4 Documentation Reviewed

The NRC staff's detailed technical evaluation of the PBAPS replacement steam dryers is based primarily on a review of the EPU LAR (Reference 1) and the following Supplements to the EPU LAR:

- Supplement 1 (Reference 2)
- Supplement 14 (Reference 15)
- Supplement 15 (Reference 16)
- Supplement 19 (Reference 74)
- Supplement 21 (Reference 76)
- Supplement 22 (Reference 77)
- Supplement 24 (Reference 107)
- Supplement 25 (Reference 108)
- Supplement 26 (Reference 114)

Some of the key documents reviewed by the NRC staff included the following Westinghouse reports:

- WCAP 17635-P, Revision 3, "Peach Bottom Atomic Power Station Unit 2 and Unit 3 Replacement Steam Dryer Comprehensive Vibration Assessment Program (CVAP)" (Attachment 4 to Supplement 24). This document summarizes the overall RSD stress analysis procedure and results.

- WCAP 17626-P, Revision 1, "Processing of Peach Bottom Unit 2 and Unit 3 MSL Strain Gauge Data and Computation of Predicted EPU Signature" (Attachment 6 to Supplement 21). This document describes measurements and processing of MSL signals, used as inputs to the dryer alternating stress estimation procedure.

- WCAP-17611-P, Revision 1, "Peach Bottom Unit 2 and Unit 3 Replacement Steam Dryer Four-Line Subscale Acoustic Test Data Evaluation and derivation of CLTP-to-EPU Scaling Spectra" (Enclosure B.5 to Attachment 17 to the EPU LAR). This document is used to establish plant conditions where the onset of flow-induced SRV standpipe resonance occurs, and to estimate bump-up-factors (BUFs) between CLTP and EPU conditions.

- WCAP-17716-P, Revision 1, "Benchmarking of the Acoustic Circuit Enhanced Revision 2.0 for the Monticello Steam Dryer Replacement Project" (Reference 113). This document describes the ACE [[ ]]

- WCAP-17590-P, Revision 2, "Peach Bottom Units 2 & 3 Replacement Steam Dryer Acoustic Load Definition" (Attachment 4 to Supplement 21). This document defines the actual loads applied to the PBAPS Units 2 and 3 RSD models.

- WCAP-17609-P, Revision 2, "Peach Bottom Unit 2 and Unit 3, Replacement Steam Dryer Structural Evaluation for High Cycle Acoustic Loads" (Attachment 5 to Supplement 22). This document explains dryer structural finite element modeling, stress analysis procedures, and final alternating stresses and stress ratios.

- WCAP-17649-P, Revision 2, "Peach Bottom Units 2 and 3 ASME Code Stress Report" (Attachment 5 to Supplement 24). This document describes ASME Code stress calculations.

- WCAP-17639-P, Revision 3, "Instrumentation Description for the Peach Bottom Unit 2 Replacement Steam Dryer" (Attachment 7 to Supplement 21). This document describes the instrumentation to be installed on the PBAPS Unit 2 replacement steam dryer.

- WCAP-17654-P, Revision 4, "Peach Bottom Unit 2 Replacement Steam Dryer Power Ascension Program Description for Extended Power Uprate" (Attachment 6 to Supplement 24). This document provides the planned course of action for monitoring and evaluating the performance of the PBAPS Unit 2 RSD during power ascension.

- WCAP-17655-P, Revision 4, "Peach Bottom Unit 3 Replacement Steam Dryer Power Ascension Program Description for Extended Power Uprate" (Attachment 7 to Supplement 24). This document provides the planned course of action for monitoring and evaluating the performance of the PBAPS Unit 3 RSD during power ascension.

2.2.6.5 Steam Dryer Design

Licensee's Input on PBAPS RSD Design

The original steam dryers at PBAPS, Units 2 and 3, were GE BWR/4, parallel vane bank slanted hood design with perforated plates at the inlet and outlet sides of the vane banks. As a part of the EPU implementation, the licensee plans to replace its original GE dryers with Westinghouse steam dryers that consist of 3-ring vane banks of octagonal shape and a cylindrical skirt. Eight nuclear plant units outside the United States (in Sweden and Finland) and one RSD in the United States (MNGP) use the Westinghouse steam dryer design. No adverse incidents with any of these installations have been reported.

In Section 5.2 of WCAP 17635-P (Attachment 4 to Supplement 24 to the EPU LAR (Reference 107)), the licensee provided information regarding several aspects of the fabrication process for the RSD that will affect the susceptibility of the RSD to intergranular stress-corrosion cracking (IGSCC) and high-cycle fatigue cracking. In the RSD design, crevices were avoided to the maximum extent possible. The RSDs are made of [[ ]] which is resistant to IGSCC. [[

]] Several precautions were taken and measures were implemented during the fabrication of the RSD to make it less susceptible to IGSCC. High cycle fatigue concerns were also taken into consideration [[ ]]

NRC Staff Evaluation

Based on successful operating experience for polygonal-shaped vane bank dryer designs operating in the Nordic region, as well as at MNGP, the PBAPS RSD design is acceptable. The design of the PBAPS RSDs use [[ ]] which is better with respect to fatigue considerations. The use of [[ ]], which is resistant to IGSCC, is acceptable to the NRC staff. The NRC staff finds that adequate precautions and considerations were implemented in the material selection and fabrication of the PBAPS RSDs to minimize susceptibility to IGSCC.

2.2.6.6 Acoustic Resonance Potential from Standpipes

The licensee performed analytical evaluations as well as subscale model tests to assess the potential for acoustic resonance from standpipes containing Dresser safety valves, Target Rock relief valves, and blind flanges. These evaluations are described in WCAP-17611-P (Enclosure B.5 to Attachment 17 to the EPU LAR (Reference 1)). The results from these evaluations are utilized in steam dryer evaluations. Additional discussion is provided in Section 2.2.6.10 on scale model tests and in Section 2.2.6.12 on BUFs.

A key part of all steam dryer alternating stress evaluations is assessing the effects of acoustic loads induced by flow-induced resonances at the various MSL valves. The acoustic mode frequencies in the valve standpipes are functions of standpipe dimensions, and are strongly excited when these frequencies coincide with those of flow instability modes across the standpipe openings driven by the MSL flow. There are specific flow rates which drive these acoustic modes, which are usually quite high, such as those at Quad Cities Nuclear Power Station. The PBAPS MSL flow velocities are 137.3 feet per sec (ft/s) at CLTP, and the estimated EPU steam velocity is 155.1 ft/s. In comparison to other BWRs that have received NRC-approved EPU license amendments, the PBAPS MSL flow velocity at EPU conditions is generally lower than the other BWRs. The flow velocities for other BWRs at EPU conditions are as follows:

- Susquehanna Steam Electric Station (SSES): 153 ft/s
- Grand Gulf Nuclear Station (GGNS): 161 ft/s
- Hope Creek Generating Station (HCGS): 167 ft/s
- Vermont Yankee Nuclear Power Station (VY): 168 ft/s
- Nine Mile Point Nuclear Station, Unit 2 (NMP2): 177 ft/s
- Monticello Nuclear Generating Plant (MNGP): 179 ft/s
- Quad Cities Nuclear Power Station, Unit 2 (QC2): 202 ft/s

The MSL flow velocities at Nordic plants, with Westinghouse octagonal dryers installed, range from [[ ]]

The MSL flow velocities, however, do not uniquely determine whether valve resonances will be excited. The valve standpipe dimensions, as well as general MSL geometry, also affect resonance excitation. Exelon, therefore, constructed and tested a [[ ]] scale model of the PBAPS RPV and MSLs to determine whether valve resonance would be excited at or before EPU conditions. The results of the subscale testing [[

]] These acoustic resonance effects are considered in the PBAPS RSD analyses for Units 2 and 3.

2.2.6.7 Steam Dryer Instrumentation

Licensee's Input

To further ensure dryer structural integrity and safety, the PBAPS Unit 2 RSD will be instrumented [[

]] The instrumented RSD will be installed at PBAPS, Unit 2, during the P2R20 refueling outage in October 2014. The [[ ]] will be used to re-benchmark the steam dryer evaluation methodology during the PBAPS, Unit 2, power ascension.

NRC Staff Evaluation

The NRC staff conducted an audit on September 12, 2013, to review the PBAPS, Unit 2, RSD instrumentation plan and determined that the on-dryer instrumentation is acceptable in terms of location, type, orientation, and redundancy. In response to an NRC RAI, the licensee submitted Supplement 21 to the EPU LAR (Reference 76). Attachment 1 to Supplement 21 contains details on the proposed instrumentation locations, justification for the locations, and plans for [[ ]] In addition to the on-dryer instrumentation which will be installed in the PBAPS Unit 2 RSD, PBAPS, Units 2 and 3, are already instrumented with strain gauges on the MSLs.

As discussed in SE Section 3.25, a license condition will be added as part of the proposed EPU for PBAPS, Unit 2. The license condition requires, in part, re-benchmarking of the end-to-end dryer analysis methodology based on the [[ ]] data collected at or near CLTP conditions during initial power ascension. Power ascension beyond CLTP is not permitted until the re-benchmarking and reestablishment of RSD minimum alternating stress ratios (MASRs). This information will be provided for NRC staff review as part of the license condition. The [[ ]] will be used to perform a PBAPS plant-specific benchmark to validate the steam dryer evaluation methodology during the PBAPS, Unit 2, power ascension. The NRC staff finds that the use of PBAPS, Unit 2, [[ ]] for performing an end-to-end benchmark provides an additional assurance to validate or confirm the structural integrity of the PBAPS RSDs.

2.2.6.8 Main Steam Line Instrumentation

Licensee's Input

As noted above, the licensee instrumented the MSLs of the PBAPS Units 2 and 3 with strain gauges. The MSL strain gauge signals are used to estimate acoustic pressures, which are input to the ACE and ACE+SPM procedures for estimating dryer load. To measure acoustic pulsations within the MSLs, Exelon instrumented the MSLs with strain gauge arrays at [[

]]

NRC Staff Evaluation

These strain gauges measure the hoop strains [[

.]] The strain gauge arrays are located at specific positions along the pipe runs [[ ]] The NRC staff finds that the number and location for placement of strain gauges on the four MSLs is consistent with those of other plants that successfully implemented EPU. There is also redundancy in the number of MSL strain gauges to address any unanticipated strain gauge failures.

The measured hoop strains are also influenced by bending strains within the MSLs, which are unrelated to internal acoustic pulsations and dryer loading. To minimize the bending effects on the measured strains, the strain gauge pairs, [[

]]
These procedures are identical to those used in the MNGP EPU application and ensure consistent data is acquired over time, minimizing any instrumentation bias errors.

Although the strain gauge calibration procedures are appropriate, problems with MSL strain gauge data acquisition at MNGP during power ascension led the NRC staff to ask Exelon in an RAI how they will ensure that similar issues do not occur during power ascension at PBAPS. As discussed in the RAI, the PBAPS stream dryer stresses in WCAP-17609-P (Attachment 5 to Supplement 22 to the EPU LAR (Reference 77)) are based on MNGP end-to-end benchmark based bias and uncertainties (B/Us) for the upper (hood) portion of the dryer. These MNGP-based B/Us were discovered, in early 2014, to be affected by an error in mislabeling of the MNGP MSL-C upper and lower strain gauge cables to the data acquisition system. As such, the NRC staff also requested the licensee to address the impact of any changes to the MNGP B/Us on the PBAPS steam dryer stresses. The licensee provided its RAI response in Supplement 26 to the EPU LAR (Reference 114). The licensee's response, in part, provided a table showing the [[ ]] to demonstrate the impact of the MNGP issue on the stresses for the PBAPS RSDs. The NRC staff reviewed the RAI response and concludes that the impact of the mislabeling of the MNGP strain gauge cables on the evaluation of the PBAPs RSDs is insignificant. The MASR values for the upper portion above the support ring (hood region) of the PBAPS RSDs are essentially unaffected. The mislabeling of MNGPs strain gauge cables has no bearing on the PBAPS RSDs' lower portion below the support ring (skirt region). The licensee's RAI response also discussed Exelon's configuration control process and use of operating experience to provide assurance that data acquisition issues, similar to those that occurred at MNGP, do not occur at PBAPS. The NRC staff finds that the licensee adequately resolved the staff's concerns regarding this issue.

2.2.6.9 Measurements and Signal Processing

Licensee's Input

WCAP-17626-P (Attachment 6 to Supplement 21 to the EPU LAR (Reference 76)) describes measurements and processing of MSL signals, used as inputs to the dryer alternating stress estimation procedure. MSL data were measured at several power levels, [[ ]] All data were checked to ensure that bad sensors were removed from the datasets, and that any spurious transients were not included in the processed signals. [[

]]

NRC Staff Evaluation

The [[ ]] performed by the licensee are reasonable. The NRC staff finds the MSL signal processing methods acceptable, since they produce reasonable spectra consistent with those observed in previous similar applications. [[ ]]

2.2.6.10 Scale Model Tests

Licensee Input

A four-line subscale model was constructed for each of the two units at PBAPS for use in two acoustic testing programs. The description of the models and test results are provided in WCAP-17611-P (Enclosure B.5 to Attachment 17 to the EPU LAR (Reference 1)). Similar to previous EPU applications, the model scale is [[

]] The main objectives of the scale model tests (SMTs) are to:

- [[

]]

- [[

]]

- Assess the effect of replacing a blind-flanged standpipe on the dead-ended leg of MSL C with a Dresser safety spring valve.

Based on the above objectives, the SMTs were performed [[

]]

NRC Staff Evaluation

The NRC staff reviewed the SMT that was performed to support the proposed EPU. The subscale model tests have their own limitations such as the materials used to build the SMTs, the fluid medium, pressures and temperatures, the duration of the blowdown test, and the geometry scale used. However, the approach used for the PBAPS subscale model testing is similar to the approach used by BWR plants in previous EPU applications. The NRC staff finds it acceptable to assess the susceptibility for safety relief valve (SRV) resonance from standpipes (see SE Section 2.2.6.6) and to obtain BUFs to project the PBAPS RSD CLTP results to EPU conditions. The steam dryer integrity will be further ensured by limit curves and by a streamlined power ascension process. Validation by the [[

]] provides the NRC staff with further assurance.

2.2.6.11 Replacement Steam Dryer Aziumuthal Orientation

The NRC staff determined that the RSD orientation for PBAPS is [[

]] Since the dynamic stress analysis of the

PBAPS RSD is based on the benchmarking data of the MNGP RSD, Exelon was requested in an RAI to explain the reasons for changing the dryer orientation from that of MNGP and to clarify the effect of this orientation change on the MSL dipole sources, which are dependent on the flow patterns at the MSL inlets.

Licensee's Input Regarding RSD Orientation in RPV

In the response to the RAI in EPU LAR Supplement 21 (Reference 76), Exelon stated that the concept of rotating the dryer was considered during the final design phase [[

]] To support this reasoning, the licensee submitted additional analysis showing that [[

]]

NRC Staff Evaluation

The NRC staff reviewed the additional analysis and rationale provided by the licensee. The NRC staff finds that the reasons provided for choosing the dryer azimuthal orientation is reasonable because the highest acoustic loading from the MSLs will be directed to a [[

]]

2.2.6.12 Bump-Up Factors

Licensee Input

Pressure spectra taken in the MSLs from the SMT were analyzed and the [[ ]] were evaluated for selected frequency ranges encompassing the acoustic resonance frequencies associated with the stand pipes of the safety valves and blind flanges. These include the frequency of the Target Rock safety relief valve (SRV) [[ ]], the Dresser spring safety valve (SSV) [[ ]], and the Blind Flanges [[ ]] The BUFs, [[ ]] were developed [[

]]

The SMT results indicate the following:

(a) The resonance of the Target Rock valve (TRV) [[ ]]

(b) The resonance of the Dresser spring valve (DSV) [[ ]]

(c) The resonance of the Blind Flange [[ ]]

(d) The acoustic resonance responses of Units 2 and 3 [[ ]] This leads to different BUFs for Units 2 and 3.

(e) The acoustic resonances of the TRVs and DSVs [[ ]]

(f) The resonance of the blind flanges [[ ]]

NRC Staff Evaluation

Since the pre-analysis and the SMT results indicate that the standpipes of the TRVs and DSVs will experience acoustic resonance [[ ]] the NRC staff requested additional information regarding the effects of the transient test conditions of the SMT on the BUFs, as well as on the degree of conservatism of the SMT acoustic pressure in comparison with SRV resonance peaks, which are determined from in-plant measurements.

During the transient blowdown tests of the sub-scale model, the tank pressure decreased from approximately 190 psig to 130 psig. In an RAI, Exelon was asked to clarify the effect of changes in the compressed air density while performing the SMT. Exelon's response, in Supplement 14 to the EPU LAR (Reference 15), provided additional results showing [[ ]]

The NRC staff also determined that some of the standpipe resonance peaks in the SMT PSDs [[ ]], which could be caused by the transient test conditions of the SMTs. Rapid depressurization of the tank is associated with reduction in air temperature and corresponding reduction in the speed of sound and the resonance frequencies. Exelon was therefore requested in an RAI to perform a sensitivity analysis [[ ]] In response to this request, Exelon submitted, in Supplement 21 to the EPU LAR (Reference 76), a sensitivity analysis [[

]]

The NRC staff reviewed the sensitivity analysis of the effect of [[
]] and concludes that these effects are carefully considered and accounted for in the BUFs. [[
]]

Although the approach of determining the BUFs from sub-scale model tests was used by previous EPU applicants, the SRV resonances in previous applications were anticipated to be either weak, because they were excited by the secondary vortex mode, or just initiating near EPU conditions and therefore their amplitude would still be small. For PBAPS, the SRV resonances could be stronger; therefore, additional information was needed to make certain that the SMT-based BUFs are conservative. Exelon was therefore requested in an RAI to compare the normalized acoustic pressures at the SRV resonance frequencies measured in the MSLs for the following three cases: (1) the sub-scale model; (2) the in-plant measurements of PBAPS; and (3) the in-plant measurements of QC2 prior to installation of the acoustic side-branches. In response to the RAI, Exelon provided, in Supplement 15 to the EPU LAR (Reference 16), [[
]]

Comparison of the normalized pressure for the three cases indicates the following:

(a) For the same reduced flow velocity in the MSLs, the [[
]]

(b) For the same reduced flow velocity in the MSLs, the [[
]]

(c) The BUFs determined from the SMT and used in the dryer stress analysis are [[
]]

Based on the above observations, the NRC staff concludes that the BUFs used in the RSD stress analysis are conservative if the SRV acoustic resonances are excited in PBAPS between

CLTP and EPU*1.02. Also, the intensity of these resonances would be [[ ]]

2.2.6.13 Steam Dryer Loads

Licensee's Input

The PBAPS RSD analyses submitted by Exelon in the EPU LAR, in September 2012, were based on the ACM Version 4.1 software developed by Continuum Dynamics Incorporated (CDI), which included documents related to steam dryers, namely nine WCAP reports, and a Startup Test plan. However, the ACM 4.1 software was [[ ]] Later, the licensee modified its approach to use an improved version of the acoustic load estimating software, namely ACE 2.0 and ACE 2.0+SPM (Skirt Protection Model) developed by Westinghouse. ACE 2.0 and the accompanying dryer vibration and stress analysis procedure was benchmarked using [[ ]] Exelon revised and resubmitted the affected RSD documents in February 2014 in Supplement 21 to the EPU LAR (Reference 76).

Two sets of dryer acoustic loads were generated for each PBAPS RSD - one using ACE 2.0 (an updated version of the Acoustic Circuit Model - ACM - described in previous successful EPU applications), and the other using ACE 2.0+SPM (Skirt Protection Model), which provides alternate higher skirt loading, which matches previous observations in the instrumented [[ ]] dryer. The ACE 2.0 loading model and the structural finite element model were benchmarked together using [[ ]] The loads are described in WCAP-17590-P (Attachment 4 to Supplement 21 to the EPU LAR (Reference 76)), and the currently used ACE and ACE+SPM benchmarking is provided in WCAP-17716-P (Reference 113).

Dryer acoustic loads are generated [[ ]] The acoustic model includes steam within and surrounding the dryer, and the mesh is dense enough to capture acoustic wave propagation up to frequencies much higher than the [[ ]] of interest for steam dryers. The [[ ]] sources are based on the MSL measurements, and an acoustic circuit model of the steam in the MSL piping. Various modeling parameters (discussed on page 2 of Attachment 1 to Supplement 25 to the EPU LAR (Reference 108)) are adjusted in the ACE 2.0 and ACE+SPM models to improve agreement between simulated and measured [[ ]] strain and pressure data, respectively.

NRC Staff Evaluation

The dryer loading procedure is the same as that used in the NRC-approved MNGP EPU application. The procedure is also reasonable and applicable to the PBAPS units since the RSDs are [[ ]] Since the MSL measurements are slightly different for PBAPS, Unit 2, and PBAPS, Unit 3, the resulting dryer loads are also slightly different. Based on examination of the source strengths and resulting dryer loading contours submitted by the licensee in EPU LAR Supplement 21, the NRC staff finds that the loading differences are reasonable.

In previous benchmarking, the [[

]]

Since the MNGP lower part of the dryer (skirt) was not instrumented, there are no measured strain data. Therefore, the corresponding end-to-end B/Us were not developed. Instead, each portion of the stress analysis procedure was benchmarked separately. For the lower dryer, [[
]] the benchmarked model is referred to as ACE 2.0+Skirt Protection Model (SPM). The individual B/Us for ACE 2.0+SPM and the B/Us for dryer structural modeling, instrumentation mounting and locations were [[

]]

The PBAPS dryer results will be further validated by the on-dryer strain measurements planned for PBAPS, Unit 2, during EPU power ascension.

2.2.6.14 Stress Analysis for Acoustic Loads on Replacement Steam Dryer

Licensee's Input

The structural evaluation of the PBAPS RSDs for high-cycle acoustic loads is presented in WCAP-17609-P (Attachment 5 to Supplement 22 to the EPU LAR (Reference 77)). The fluctuating acoustic pressure loading, described above in SE Section 2.2.6.13, was applied to a structural finite element model of the RSDs. Finite element analysis (harmonic analysis in frequency domain) was performed using the ANSYS general purpose finite element code. Structural damping of 1% of critical damping was applied for all frequencies and is in accordance with RG 1.20 (Reference 109). Hydrodynamic damping [[
]] was also used in the structural analysis.

The ANSYS general purpose finite element program software was used to perform the stress analysis of the PBAPS RSDs subject to acoustic loads under EPU operating conditions. The PBAPS RSD finite-element models (FEMs) are described in WCAP-17609-P. PBAPS, Unit 2, has an instrumentation mast and the associated brackets on the dryer top girders for attaching the mast. PBAPS, Unit 3, does not have an instrumentation mast. For the PBAPS, Unit 2, RSD, FEMs with and without an instrumentation mast were utilized. The PBAPS, Unit 2, instrumentation mast will be in place during power ascension to EPU and subsequent completion of the end-to-end benchmark. In the future, the instrumentation mast will be removed.

The FEMs for the RSD mostly consist of [[

]]

NRC Staff Evaluation

The NRC staff reviewed the PBAPS RSD structural finite element modeling, the boundary conditions, and stress analysis for acoustic loads. The approach and methodologies utilized for PBAPS are reasonable and consistent with dryer analyses in the previous NRC-approved EPU applications. The structural evaluation performed by the licensee follows the guidance from BWRVIP-182-A (Reference 110), RG 1.20 (Reference 109), RS-001, and SRP Section 3.9.5. Based on the review of the information provided by the licensee, the NRC staff finds that the FEMs and the boundary conditions reasonably depict the RSDs and therefore are acceptable.

2.2.6.15 Finite Element Analysis of Replacement Steam Dryer

Licensee's Input

Consistent with previous NRC-approved BWR EPU applications, for PBAPS, the licensee computed dryer stresses [[

]] The worst-case stresses were then used to determine the minimum alternating stress ratio (MASR). The PBAPS FEM of the RSD is sufficiently accurate [[ ]]

In the finite element stress analysis of the RSD (WCAP-17609-P), the licensee included hydrodynamic damping [[

]]

In constructing the FEM of the RSD, the fluid-structure interaction phenomenon between the immersed portion of the skirt and the reactor water was modeled [[ ]] As in previous applications, industry-accepted correlations were used [[ ]]

The inner and outer surface pressure loading on the dryer FEM was interpolated from the ACE 2.0 solutions for the upper dryer and ACE 2.0+SPM solutions for the lower dryer using ANSYS surface definitions and data tables. Both the inner and outer surface resultant nodal forces were applied simultaneously, leading to the appropriate pressure difference applied to the FEM.

NRC Staff Evaluation

The NRC staff has previously reviewed and approved the concept and methodology of introducing hydrodynamic damping [[ ]] as discussed in the staff's SE for the NMP2 EPU (ADAMS Accession No. ML113300040). However, since the stress analysis report for PBAPS (WCAP-17609-P) did not include any information about the damping value, which is used in the analysis, Exelon was requested in an RAI to explain the amount of damping [[ ]] The response to this RAI indicated that the value of the hydrodynamic damping coefficient used for PBAPS [[ ]] than that previously approved by NRC staff. The licensee also provided the dryer stress ratios with and without consideration of hydrodynamic damping. For PBAPS, Unit 2, the dryer stresses [[ ]] when hydrodynamic damping is not considered resulting in a decrease of MASR from 1.49 to 1.38.

The MSL signals and the hood (upper part of the dryer) strains, measured at CLTP on the MNGP RSD, allowed the MNGP licensee to perform end-to-end benchmarking and develop the corresponding B/Us. These B/Us were used in estimating the stresses in the hood at EPU conditions. These B/Us cannot be used for estimating the stresses in the skirt (lower part of the dryer) because the modal characteristics of the skirt are different than those of the hood. The skirt has several natural frequencies that are lower than the lowest natural frequency of the hood. [[ ]]

For PBAPS, Units 2 and 3, the MASRs for the hood regions of the RSDs is greater than 1.0 and is acceptable because the stress analysis for the hood regions is based on B/Us developed from the MNGP end-to-end benchmark. The MASRs for the skirt regions for the PBAPS, Units 2 and 3, though less than the goal of 2.0, are acceptable based on the following considerations: (1) Exelon utilized individual B/Us, for each portion of the analysis, some of which have some conservatism; and (2) Exelon will confirm these results based on the evaluation to be performed at CLTP using PBAPS Unit 2 [[ ]] of the PBAPS, Unit 2, RSD. The NRC staff therefore concludes that there is reasonable assurance that the PBAPS, Units 2 and Unit 3, dryer skirts and hoods will not experience any fatigue cracking during operation at EPU conditions.

The licensee employed a computationally efficient stress analysis approach for calculating the transient stress response of the PBAPS RSDs to pressure fluctuations in the steam dome. This approach was previously used by PSEG Nuclear, LLC, in the stress analysis of the Hope Creek Generating Station steam dryer stress analysis under EPU conditions, and was found to be acceptable by the NRC. The traditional direct time-history analysis requires long computation times and includes the transient solution associated with inaccurate initial conditions (typically, zero displacement and velocity), while the more computationally efficient approach, based on harmonic analysis conducted in the frequency domain, provides a steady state solution. In addition, the harmonic analysis allows for applying specified damping (1% of the critical modal damping) for the whole range of the natural frequencies of the steam dryer.

Due to the large number of time points in the time-history, the calculation of the alternating stress intensity is also a computationally-intensive process. Because the alternating stress for a large number of the nodes will not be significant, [[ ]] The NRC staff reviewed the FE stress analysis of the PBAPS RSDs, in addition to the B/Us and utilized weld factors, and finds the structural analysis of the dryer to be acceptable.

2.2.6.16 Fatigue Assessment of Welds

Licensee's Input

The RSD fabrication mainly includes full-penetration welds with fillet welds joining the perforated plate onto the inlet face of the dryer vane banks. The weld stresses calculated using weld factors bound the stresses calculated according to the ASME Code, Subsection NG. The stresses due to the acoustic loads were added to those due to the reactor recirculation pump (RRP) vane passing frequency (VPF) loads. The resulting alternating stress intensities satisfy the requirement of a minimum stress ratio of 1.0 for the hood. The minimum stress ratios in the skirt are [[ ]] for Unit 2, and [[ ]] for Unit 3. These ratios include stress concentration factors (SCFs) of [[ ]] Some fillet welds are single-sided and others are double-sided. The total throat size of each fillet weld is [[ ]] Using examples, the licensee demonstrated that the stresses calculated with SCFs are higher compared to those using ASME Code, Subsection NG, Table NG-3352-1. If the stresses calculated using the SCFs are higher than allowable, then the licensee uses the ASME Code, Section III for the fatigue assessment.

NRC Staff Evaluation

The NRC staff reviewed the weld factors utilized in the PBAPS steam dryer evaluations. The weld factors, which were demonstrated to be conservative, were compared to those in Subsection NG of Section III of the ASME Code. These weld factors are consistent with those used in the previous NRC-approved EPU applications. Based on these considerations, the NRC staff finds that the weld factors used in the PBAPS steam dryer evaluations are acceptable.

2.2.6.17 Stress Analysis of the Hood (Upper Part of the Dryer)

Licensee's Input

The licensee applied fluctuating acoustic pressure loading, generated from the ACE 2.0 code, to the structural FEM of the dryer for predicting stresses in the hood. The licensee applied the following B/Us to the predicted stresses: [[

]] The maximum stress in the upper dryer subject to acoustic loads at EPU is [[

]] This corresponds to a minimum alternating stress ratio (MASR) of [[
]] for PBAPS Unit 2. If no credit is taken for [[
]] the MASR for PBAPS Unit 2 [[
]] as discussed in Supplement 25 to the EPU LAR (Reference 108).

The MASR values (acoustic plus VPF effects) for the hood portion of the RSD are [[
]] for PBAPS, Units 2 and 3, respectively.

NRC Staff Evaluation

The MASR values for the hood portion of the RSD are [[ ]] for PBAPS, Units 2 and 3, respectively. If [[ ]], the MASR for PBAPS, Unit 2, reduces from [[ ]] a slight reduction of about [[ ]] Since the MASR for the hood portion is based on B/Us generated from the MNGP end-to-end benchmark, values greater than 1.0 are acceptable for PBAPS, Units 2 and 3. The NRC staff finds the stress evaluation for the hoods acceptable because it meets the recommended acceptance limit.

2.2.6.18 Stress Analysis of the Skirt (Lower Part of the Dryer)

Licensee's Input

The licensee employed the ACE 2.0+SPM code for predicting stresses in the skirt. The licensee applied the following B/Us (see Tables 3-4 and 3-6 of WCAP-17590-P) to the predicted stresses: [[

]] Even though they are below the recommended goal of 2.0, they are considered acceptable based on the following discussion. These MASRs are based on [[

]] As previously noted, the PBAPS Westinghouse RSD is of a different design (3-ring octagonal shape vane bank type), as compared to the spare GE steam dryer on which a shaker test was performed.

The MASR values (acoustic plus VPF effects) for the skirt portion of the RSD are [[ ]] for PBAPS Unit 2 and PBAPS Unit 3, respectively. The maximum stress in the lower dryer at EPU is [[ ]] This corresponds to the stress ratio of [[ ]]

NRC Staff Evaluation

The NRC staff reviewed the evaluations performed by the licensee for the skirt of the PBAPS RSDs. Since the skirt analysis [[ ]] The limiting MASR values (acoustic plus VPF effects) for the skirt portion of the RSD are [[ ]] for PBAPS, Units 2 and 3, respectively, which are lower than 2.0, the recommended MASR for the skirt [[ ]] However, the staff finds the skirt MASRs acceptable because MASRs greater than 1.0 indicate that the skirt stresses are below the endurance limit of 13,600 psi. Further, Exelon will validate to confirm the results based on the planned evaluation at CLTP using PBAPS, Unit 2, [[ ]] that will also include strain gauges on the skirt of the PBAPS, Unit 2, RSD. Thus, during power ascension of PBAPS Unit 2, the structural integrity of the skirt will be verified using [[ ]] strain gauge data. The PBAPS, Unit 2, RSD is a prototype for the PBAPS, Unit 3, RSD. Therefore, the NRC staff concludes that there is reasonable assurance that the PBAPS, Units 2 and 3, dryer skirts will not experience any fatigue cracking during operation at EPU conditions.

2.2.6.19 Sub-modeling

Licensee's Input

It is not practical to perform a global analysis of the RSD using a very fine mesh because of the size of the FEM and the computational efforts involved. Therefore, a mesh density is used that can accurately predict the dynamic characteristics (i.e., mode shapes and frequencies) of the structure and, therefore, nodal forces and moments. Such mesh density cannot accurately model the curvatures, thickness transitions and other geometric details such as slots. As such, the high stress locations in the RSDs require further analysis using sub-modeling so that the geometric features can be properly modeled and the stresses can be accurately predicted. Sub-model analysis may predict stresses that are higher or lower than those predicted in the global analysis, depending upon the type of geometric details not modeled in the global analysis.

Based on the results of the global analysis, [[ ]] were identified for sub-model analysis. To better represent the local geometry, detailed sub-models for the [[ ]] were created, [[ ]] The sub-model analyses provide lower stresses at the majority of the high stress locations; the stresses reduced by [[ ]] One exception was the [[ ]] where stresses increased by about [[ ]]

NRC Staff Evaluation

The licensee has properly applied the acoustic loads and the corresponding B/Us to the dryer for predicting the stresses in the dryer. These loads were developed with the ACE 2.0 and ACE 2.0+SPM codes that were benchmarked using the strain and pressure measurements, respectively, from the instrumented dryers. The application of sub-models allows the use of finer mesh for modeling the structural details that cannot be represented in the global model. Thus, sub-modeling provides more accurate prediction of the stresses and, therefore, its use is acceptable. The MASR for predicted stresses is less than the target value of 2.0. However, it is greater than 1.0, thus meeting the ASME Code endurance limit. The licensee will further validate and confirm the structural integrity of the PBAPS, Unit 2, dryer by reanalysis, using the [[ ]] measured data at CLTP and will demonstrate that the MASR at EPU is greater than 1.0. This reanalysis of the PBAPS, Unit 2, RSD is included as a licensing condition as shown in SE Section 3.25. PBAPS, Unit 3, will subsequently utilize B/Us based on PBAPS, Unit 2, on-dryer based end-to-end benchmark and will also demonstrate that the MASR at EPU is greater than 1.0.

2.2.6.20 Stress Peaks

Licensee's Input

In response to an RAI, the licensee, in Supplement 21 to the EPU LAR (Reference 76), provided stress accumulation plots of dominant stress components at the highest stress locations. The accumulation plots show how individual frequency regions contribute to the overall RMS alternating stresses. [[

]] It is possible that there is a strong structural resonance at this frequency. The licensee was therefore requested in an RAI to explain the source of the peak [[
]] In its response, (Supplement 24 to the EPU LAR (Reference 107)), Exelon stated that [[

]]

NRC Staff Evaluation

Based on the review of the licensee's responses, the NRC staff notes that the stress peaks [[
]] are likely due to dryer's structural response at this frequency. Since the steam dryer stresses include responses up to [[ ]] the staff finds the basis for the stress peaks provided by the licensee in its RAI responses (and included in the overall steam dryer stresses at EPU conditions) to be acceptable.

2.2.6.21 Stresses Induced by Reactor Recirculation Pumps

Background

As part of the development of the acoustic load response, Exelon [[

]]

However, experiences with other BWR plants have shown that tonal pulsations emanating from the reactor recirculation pumps (RRPs) propagate through the piping and the RPV and into the dryer via the dryer support brackets and via the MSL supports. The pulsations occur at the VPFs of the pumps, and the tones are clearly visible in strain gauges mounted to currently operating steam dryers. In some cases, the alternating stresses induced in a dryer by the VPF tones have been comparable to those caused by acoustic loading on the dryer surfaces. Also, if the RRP VPFs can shift in frequency as operating conditions change, their influence on dryer stresses can vary considerably as the tones may align with different dryer resonances. This shifting effect is not captured by the broad-band B/Us associated with the acoustic dryer loading calculations. Therefore, EPU applicants are requested, by the NRC staff, to account separately for the dryer stresses caused by RRP VPF tones.

Licensee's Input

[[

]]

NRC Staff Evaluation

The NRC staff concludes that the licensee has conservatively accounted for the VPF effects from the recirculation line structural path. The contribution from the VPF effects to the PBAPS RSD stress is small. [[ ]] As a further validation, the VPF induced dryer stresses will be [[ ]] during power ascension and will be included in the PBAPS specific end-to-end benchmark.

2.2.6.22 Limit Curves

Licensee's Input

In Attachment 17 to the EPU LAR (Reference 1), the licensee provided MSL-based limit curves for use during power ascension for PBAPS, Unit 2, (in WCAP-17654-P) and for PBAPS, Unit 3 (in WCAP-17655-P). The initially submitted limit curves in Reference 1 for both units were based on measured signals at CLTP and the corresponding highest alternating stress intensity derived from the RSD stress analysis at EPU. The limits for PBAPS, Unit 2, will be updated during power ascension and will be based on the RMS values of measured strains from the on-dryer strain gauges.

The limit curves for PBAPS, Unit 3, will be updated during power ascension and will be based on the measured MSL strain gauge signals. [[ ]] Two sets of curves are generated: (1) Level 1 limit curves based on the ASME Code limit of 13,600 psi; and (2) Level 2 limit curves based on 80% of the ASME Code limit.

However, PBAPS, Unit 2, will not use the MSL strain gauge based limit curves. Instead, after the PBAPS, Unit 2, RSD is installed, Exelon will generate the RMS strain limits for on-dryer strain gauges based on the on-dryer measured strains at or near CLTP for use during the power ascension. [[

]]

If any of the Level 1 RMS strain limits for Unit 2 or limit curves for Unit 3 are violated, Exelon will reanalyze the dryer alternating stresses. ACE will be used in the reanalysis of the hood and skirt with the same or separate end-to-end B/Us and the resulting stresses will be combined with the corresponding VPF stresses. The highest combined stress will be compared with the allowable ASME fatigue limit of 13,600 psi and, if smaller, then it may be used to develop new limit curves.

NRC Staff Evaluation

The dryer response and excitation will be monitored during power ascension using limit curves to ensure that any resonances will not challenge the steam dryer alternating stress intensity limits. The licensee's approach for use of limit curves during power ascension is similar to what has been successfully used by the other licensees during previous EPU power ascensions to monitor steam dryer structural integrity. Therefore, the NRC staff finds the PBAPS limit curve approach during EPU power ascension to be acceptable.

2.2.6.23 Replacement Steam Dryer Stresses for Service Levels A, B, C, and D

Licensee's Input

In addition to the evaluation for FIV loading and high-cycle fatigue, in the PBAPS, Units 2 and 3, ASME Code Stress Report (WCAP-17649-P), included in Supplement 24 to the EPU LAR (Reference 107), the licensee also evaluated the steam dryer for load combinations for Service Levels A through D, to demonstrate structural integrity of the RSDs. The licensee utilized Subsection NG of Section III of the ASME Code for guidance. Plant-specific load combinations were followed. For normal conditions (Service Level A), the load combinations included dead weight (DW), differential static pressure (ΔP_N) and FIV. The loads utilized for upset conditions (Service Level B) include DW, differential pressure (ΔP_U), Operating Basis Earthquake (OBE) and FIV or acoustic load caused by Turbine Stop Valve (TSV) closure and FIV. The vane passing frequency (VPF) loads were included with FIV loads. The emergency condition (Service Level C) loads included DW, differential static pressure (ΔP_E), and FIV. The faulted condition (Service Level D) loads included DW, differential static pressure (ΔP_F), Safe Shutdown Earthquake (SSE), loads from a MSL break (MSLB) outside containment, and FIV.

The membrane and membrane plus bending stress intensities were computed and compared with the allowable limits. The allowable limits for the membrane stress intensities are respectively $1S_m$, $1.1S_m$, $1.5\ S_m$, and a minimum (of $0.7S_u$ or $2.4\ S_m$) for normal, upset, emergency, and faulted conditions, where S_m (=14.4 ksi) and S_u (=61.7 ksi) are respectively the allowable stress intensity and tensile strength of the material at the applicable temperature (551°F). The material for the steam dryer structural components is SA-240 Type 316L. The allowable limits for membrane plus bending stress intensities are respectively $1.5S_m$, $1.65S_m$, $2.25\ S_m$, and minimum of 1.5 ($0.7S_u$ or $2.4\ S_m$) for normal, upset, emergency, and faulted conditions. A weld quality factor (n) of [[ ]] was applied to the allowable stress intensity for the primary stress evaluations, except for the [[ ]] where a quality factor of [[ ]] was used. The allowable stress limit for Levels A and B primary plus secondary stress range is $3\ S_m$. The primary plus secondary stress range check was not performed for the steam dryer because the secondary stresses were negligible, since the dryer operates under isothermal conditions. The structural design of the dryer does not have materials of variable thermal expansion coefficients. The Code edition utilized was the 2007 Edition with the 2008 Addenda of the ASME Code, Section III, Division 1, Subsection NG. The ratios of the allowable membrane stress intensity to the computed membrane stress intensity for the dryer for the most limiting components and welds shown in WCAP-17649-P are as follows:

Normal Service Level A
(Allowable P_m for components= $S_{m;}$; Allowable P_m for welds = n.S_m)
[[

]]

Upset Service Level B
(Allowable P_m for components = $S_{m;}$ or 1.1 S_m : Allowable P_m for welds = (1 or 1.1) n.S_m)
[[

]]

Emergency Service Level C
(Allowable P_m for components = 1.5$S_{m;}$; Allowable P_m for welds = 1.5 n.S_m)
[[

]]

Faulted Service Level D
(Allowable Pm for components = 2.4Sm; Allowable Pm for welds = 2.4 n.Sm)
[[

]]

The ratios of the allowable membrane plus bending stress intensity to the computed membrane plus bending stress intensity for the dryer at the most limiting component for EPU conditions shown in WCAP-17649-P are as follows:

Normal Service Level A
(Allowable Pm + Pb for components = 1.5 Sm; Allowable Pm + Pb for welds= 1.5 n .Sm)
[[

]]

<u>Upset Service Level B</u>
(Allowable Pm + Pb for components = 1.5 Sm; or 1.65 Sm)
(Allowable Pm + Pb for welds = (1.5 or 1.65) n.Sm)
[[

]]

<u>Emergency Service Level C</u>
(Allowable Pm + Pb for components = 2.25Sm; Allowable Pm + Pb for welds = 2.25 n.Sm)
[[

]]

<u>Faulted Service Level D</u>
(Allowable Pm + Pb for components = 3.6 Sm; Allowable Pm + Pb for welds = 3.6 n.Sm)
[[

]]

The licensee computed the cumulative fatigue usage factor (CUF) due to ASME loads and concurrent FIV/VPF loads. The computed CUF for the RSD is [[ ]] which is insignificant. It is also noted that the stresses from the FIV/VPF loads independent of the ASME loads, are below the ASME Code endurance limit for steam dryer material, which is stainless steel.

NRC Staff Evaluation

The licensee utilized Subsection NG of Section III of the ASME Code and plant-specific load combinations to evaluate steam dryer stresses and establish steam dryer acceptability for normal, upset, emergency, and faulted conditions with appropriate allowable limits. Based on a review of the above results, the NRC staff finds the results for the steam dryer stress intensities are acceptable for the normal, upset, emergency, and faulted load combinations under EPU conditions, because the ratios of allowable stress intensities to maximum computed stress intensities are all greater than 1.0, thus meeting the applicable Code limits.

2.2.6.24 End-to-End Benchmarking Procedure

Licensee's Input

A replacement steam dryer (RSD) with on-dryer instrumentation is planned to be installed during the fall 2014 refueling outage (P2R20) for PBAPS, Unit 2. After the installation of the RSD, the on-dryer strain gauge data, and the MSL strain gauge data that will be collected at or near CLTP and EPU will be utilized to develop an end-to-end benchmark. In response to an NRC staff RAI, the licensee, in Supplement 25 to the EPU LAR (Reference 108), submitted a planned step-by-step procedure, for determining end-to-end B/Us and maximum dryer stresses for PBAPS, Unit 2, based on the [[ ]] data to be collected at or near CLTP and at EPU conditions. The initial approach will be to have a [[ ]] An evaluation, to ensure that this [[ ]] is appropriate, will be performed. If that is found to be not appropriate, then [[ ]] will be developed. A summary of the licensee's end-to-end benchmarking procedure is as follows:

[[

]]

NRC Staff Evaluation

The NRC staff reviewed the step by step benchmarking procedure provided in Supplement 25 to the EPU LAR. This procedure provides for the development of a PBAPS-specific benchmark, based on PBAPS, Unit 2, [[ ]] data at or near CLTP and at EPU conditions during the PBAPS, Unit 2, power ascension. The staff finds that this procedure is acceptable because it ensures that the predicted strain PSDs, as well as the RMS strain, bound the measured strain PSDs and RMS strain at the dominant frequencies. The application of the above step-by-step procedure further validates and confirms the structural integrity of the steam dyer.

2.2.6.25 Power Ascension and Testing Plan

This SE section focuses on the evaluation of the EPU power ascension and testing plan (PATP) related to the RSDs. Further evaluation of the PATP is provided in SE Section 2.12.

Licensee's Input

For implementation of the EPU at PBAPS, Exelon will conduct comprehensive startup testing. Attachment 10 to the EPU LAR (Reference 1) describes the startup testing that Exelon intends to perform following the EPU implementation outages at PBAPS, Units 2 and 3.

EPU tests will have Level 1 and Level 2 acceptance criteria. Level 1 criteria are associated with design performance. If a Level 1 test criterion is not met, the plant will be placed in a hold condition that is judged to be satisfactory and safe, based upon prior testing. Resolution of the problem will be immediately pursued by equipment adjustments or through engineering evaluation, as appropriate. The problem resolution plan will be presented to the Plant Operations Review Committee (PORC) for approval prior to implementing corrective actions. The applicable test portion will be repeated to verify that the Level 1 requirements are satisfied and the results presented to the PORC for approval, prior to increasing reactor power.

Level 2 criteria are associated with performance expectations. If a level 2 criterion is not met, an evaluation will be initiated to identify the cause and actions necessary to correct the problem. The results of the evaluation will be presented to the PORC for approval prior, to implementing corrective actions. If physical adjustments are required, the applicable test portion will be repeated to verify that the Level 2 requirements are satisfied prior to increasing reactor power.

The power ascension program (PAP) for the PBAPS RSDs was provided in Supplement 24 to the EPU LAR (Reference 107). The PAP for the PBAPS, Unit 2, RSD is contained in WCAP-17654-P and the PAP for the PBAPS, Unit 3, RSD is contained in WCAP-17655-P.

Steam dryer/separator performance will be confirmed to be within limits by determination of steam moisture content during power ascension testing. Vibration monitoring of main steam and feedwater piping will be performed to assess the effects of the EPU. The three main elements of the RSD PAP are as follows: (1) a slow and deliberate power ascension with defined hold points and durations allowing time for monitoring and analysis; (2) a detailed power ascension monitoring and analysis program to trend steam dryer performance through the monitoring of the MSL strain gauges for PBAPS, Unit 3; MSL strain gauges and [[ ]] for PBAPS, Unit 2; and moisture carryover; and (3) an inspection and analysis program to verify steam dryer and piping system performance. Relevant data and evaluations will be transmitted to the NRC staff during the power ascension in accordance with the license conditions described in SE Sections 3.25 and 3.26.

This plan incorporates requirements from RG 1.20 (Reference 109). This plan includes specific hold points and durations during power ascension; activities to be accomplished during hold points; data to be collected; required inspections and walk downs; data evaluation methods; and acceptance criteria for monitoring and trending plant parameters.

At approximately each 2% power ascension step, the licensee will obtain and evaluate data to acceptance criteria. In addition, high moisture carryover (MCO) values may be indicative of off-normal steam dryer performance during power ascension. This plant information can provide an early indication of unacceptable steam dryer performance. Monitoring plant data (including MCO) and taking appropriate action when necessary is part of the PAP.

The PBAPS PAP will provide for power ascension monitoring and analysis to trend steam dryer performance. At every 2.0% CLTP step, MSL strain gauge and [[ ]] data (for PBAPS, Unit 2) will be collected and evaluated against acceptance limits. At every 4% CLTP plateau, the data will be evaluated against the acceptance criteria and information will be forwarded to the NRC. RSD stress for all power ascension steps above CLTP conditions will be collected using either on dryer strain gages (Unit 2) or MSL strain gauge readings (Unit 3). Evaluation of the power ascension data will be by comparison against the limits, and will be provided to the NRC prior to further power ascension. The Unit 2 strain and Unit 3 stress criteria will have two threshold action levels, where exceeding Level 1 criteria requires that power be reduced to a previous acceptable level and exceeding Level 2 criteria requires that power be held at that level with a re-evaluation of the data.

Upon completion of the power ascension to EPU, Exelon will prepare a report on the performance of the steam dryer and plant systems during the EPU power ascension. The report will include evaluations or corrective actions that were required to obtain satisfactory steam dryer performance. The report will also include relevant data collected at each power step, comparisons to performance criteria (design predictions), and evaluations performed in conjunction with the steam dryer structural integrity monitoring. Exelon will submit a report to the NRC with the results of the PBAPS PAP following completion of the EPU power ascension, in accordance with the license conditions discussed in SE Sections 3.25 and 3.26.

As part of the normal plant monitoring program, Exelon will monitor plant parameters indicative of degradation of the steam dryer or plant systems during EPU operation. For example, MCO will be monitored. In accordance with the license conditions discussed in SE Sections 3.25 and 3.26, during the first two scheduled refueling outages (RFOs) after reaching EPU conditions, for each of the PBAPS units, a visual inspection will be conducted of the steam dryer as described in the inspection guidelines contained in WCAP-17635-P (Attachment 4 to Supplement 24 to the EPU LAR (Reference 107)). The steam dryer visual inspections, during the first RFO following EPU implementation, will be based on experience from inspections of the Westinghouse steam dryers from Sweden, Finland, and MNGP. The inspections will also use guidance from BWRVIP-139-A (Reference 112), BWRVIP-181-A (Reference 111), RG 1.20 (Reference 109), and areas of accessible high stress locations based on structural analysis results. The results of the visual inspections of the steam dryer will be reported to the NRC staff within 90 days following startup from each of the first two respective RFOs, in accordance with the license conditions discussed in SE Sections 3.25 and 3.26.

<u>PBAPS Unit 2 RSD PAP</u>:

WCAP-17654-P, Revision 4, describes the PBAPS, Unit 2, RSD PAP. The PBAPS, Unit 2, RSD PAP assesses the steam dryer performance for the EPU power level startup power ascension process.

Both steam dryer indirect monitoring using MSL strain gauges and direct dryer monitoring will be performed. The primary approach to justify continued power ascension will be based on RSD strain gauge data. RSD strain gauge data will be compared to the root mean square (RMS) strain limits. In addition to the RMS strain limits, the dominant peaks in the dryer strain gauges will also be monitored.

The data from the RSD accelerometers and pressure transducers will be utilized as supplemental data. In addition, the [[ ]] data will be utilized to perform a trending evaluation during the power ascension. Strain values from the [[ ]] will be used to ensure the ACE 2.0 and ACE 2.0+SPM methodologies used are conservative. Evaluation of the RSD strain gauge data and validation of acceptance criteria will be performed by comparison against pre-determined strain limits as follows:

- Level 1 strain limits are defined to be the [[ ] reported to the NRC.
- Level 2 strain limits are defined to be [[ ]]

The following three possibilities may occur, depending on the magnitude of the measured RMS strain:

1. If the strain (RMS) < Level 2, the power may be increased to the next level.
2. If Level 2 < Strain (RMS) < Level 1, the power is held and a stress analysis using MSL gauge plant data at the current power level strain will be performed to calculate a new MASR, predicted strains and new limits. If the new MASR is acceptable, then only power ascension to the next level is continued.
3. If Strain (RMS) > Level 1, then power is reduced to the previous step, and an engineering evaluation of the dryer is performed to determine a new predicted MASR and strain gauge

RMS limits. If the new predicted MASR is greater than 1.0, then continuation of power ascension is acceptable.

In the event that the direct RSD strain gauge measurement limits are exceeded, then the MSL strain gauge data, in conjunction with the PBAPS-specific benchmarked ACE methodology, will be utilized to determine a revised minimum alternating stress intensity and predicted strain values. These values will then be utilized to create a revision to the RMS strain limit data set.

PBAPS, Unit 2, RSD PAP Test Level A:

The RSD PAP Test Level A includes the collection of data from low power (less than 25% CLTP) to 3514 MW.

In accordance with the license condition shown in SE Section 3.25, Exelon will perform a re-benchmarking of the ACE 2.0 methodology by collecting data [[ ]] This initial end-to-end benchmarking will be performed at a power level between [[ ]] The initial approach will be to benchmark a [[ ]]

A brief stress summary report for the RSD based on the MSL strain gauge and on-dryer instrument data collected between 90% and 100% CLTP will be provided to the NRC for review prior to exceeding CLTP in accordance with the license condition shown in SE Section 3.25.

PBAPS, Unit 2, RSD PAP Test Level B:

The RSD PAP Test Level B includes the collection of data from 100% CLTP to 112.4% CLTP.

Steam dryer direct data will be evaluated against the acceptance criteria at each nominal 2% power level increment above 3514 MWt. [[ ]] The duration of the individual power ascension steps will be determined by the time required to obtain the specified data, complete the data evaluation, and determine the acceptability of proceeding to the next power ascension step.

A summary of the comparison between the RSD strain gauge data to the RMS strain limits will be provided to the NRC for review at approximately 104% and 108% of 3514 MWt, in accordance with the license condition shown in SE Section 3.25. In the event limits are exceeded, the evaluation of continued structural integrity of the steam dryer and revised limits will be provided to the NRC for review.

In accordance with the license condition shown in SE Section 3.25, the results of the power ascension testing for the RSD will be submitted to the NRC in a report within 90 days of the completion of the PBAPS, Unit 2, EPU power ascension testing. The report will include a final load definition and stress report, based on the results of a complete re-analysis using the end-to-end bias errors and uncertainties determined at EPU conditions. A comparison of predicted and measured pressures and strains on the RSD during power ascension will also be included in this 90-day report.

PBAPS, Unit 3, RSD PAP:

WCAP-17655-P, Revision 4, describes the PBAPS, Unit 3, RSD PAP. The PBAPS, Unit 3, PAP assesses the steam dryer performance for the EPU power level startup power ascension process and is similar to the PBAPS, Unit 2, PAP, except that the steam dryer monitoring is based on MSL strain gauge limit curves.

MSL strain gauge data will be compared to limit curves to justify continued power ascension. The limit curve methodology, using the indirect dryer monitoring, is expected to bound the stress measurements predicted on the dryer due to the conservatisms in the ACE 2.0 and ACE 2.0+SPM methodologies. Therefore, MSL strain gauges will be relied upon for the determination of the ability to continue power ascension.

Limit curves for MSL strain gauges are presented in WCAP-17655-P. Upon completion of the PBAPS, Unit 2, EPU power ascension, a re-benchmarking of the [[ ]] will be performed. This re-benchmarking will utilize [[ ]] This newly re-benchmarked [[ ]] will then be applied to PBAPS, Unit 3, to determine and update the structural analyses presented in WCAP-17609-P. The limit curves for PBAPS, Unit 3, will be updated using the revised stress ratios. For additional details, see SE Section 2.2.6.22 on Limit Curves and the description of the PBAPS, Unit 2, RSD PAP, above, for similar actions when Level 1 and Level 2 limits are exceeded.

NRC Staff Evaluation

The NRC staff reviewed the PBAPS, Units 2 and 3, PAPs, and startup test plans for their ability to provide a slow and deliberate power ascension that allows for monitoring of plant data, evaluating steam dryer and system performance, and taking corrective action in the event that plant data reveal that such action is appropriate. Further, the NRC staff compared the proposed license conditions for PBAPS with those applied during the previous EPU power ascensions. The NRC staff finds that the PBAPS PAPs are in accordance with the guidelines in RG 1.20. In addition, the staff finds that the dryer inspections follow the guidance from RG 1.20, BWRVIP-181-A, BWRVIP-139-A, Westinghouse steam dryer operating experience, and will also focus on areas of high stress locations from structural analysis, and therefore are acceptable. The PBAPS, Unit 2, RSD has on-dryer instrumentation, the data from which coupled with MSL strain gauge data, will be used to perform an end-to-end benchmark at or near CLTP. The PBAPS, Unit 3, RSD only has MSL strain gauges and considers PBAPS Unit 2 as the prototype. The PBAPS, Unit 3, RSD analysis will be updated to use B/Us from the PBAPS, Unit 2, end-to-end benchmark after the completion of the PBAPS, Unit 2, power ascension. The NRC staff finds that the PBAPS PAPs and the applicable license conditions shown in SE Sections 3.25 and 3.26 provide an acceptable power ascension process that is consistent with the successful approach employed during power ascension at other BWR plants that have implemented an EPU.

Conclusion

The NRC staff reviewed the licensee's evaluations of potential adverse flow effects on the PBAPS, Units 2 and 3, RSDs for the operation at EPU conditions, as discussed above in SE Sections 2.2.6.1 through 2.2.6.25. The staff concludes that the licensee has provided reasonable assurance that the flow-induced and mechanically-induced effects on the RSDs are within the structural limits at the CLTP conditions and the extrapolated EPU conditions. As such, and subject to the license conditions in Sections 3.25 and 3.26 of this SE, the NRC staff concludes that there is reasonable assurance that the PBAPS RSDs will maintain their structural integrity at the projected EPU conditions.

Based on the above evaluation, the NRC staff further concludes that the licensee has demonstrated that the RSDs will meet the requirements of draft GDCs 1, 2, 4, 40, and 42, following implementation of the proposed EPU at PBAPS. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the structural integrity of the RSDs.

2.3 Electrical Engineering

2.3.1 Environmental Qualification of Electrical Equipment

Regulatory Evaluation

Environmental qualification (EQ) of electrical equipment demonstrates that the equipment is capable of performing its safety function under significant environmental stresses which could result during and following design-basis accidents (DBAs). The NRC staff's review focused on the effects of the proposed EPU on the environmental conditions that the electrical equipment will be exposed to during normal operation, anticipated operational occurrences, 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 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.

Technical Evaluation

The NRC staff's EQ review consisted of reviewing the EPU LAR dated September 28, 2012, and the licensee's responses to the NRC staff's RAI provided in its letters dated June 4, 2013 (Reference 5), and January 31, 2014 (Reference 19). In PUSAR Section 2.3, the licensee stated that all electrical equipment in the EQ program was evaluated by developing a list of components that are identified as part of the program. In its evaluation, the licensee analyzed the changes to existing qualification of safety-related electrical equipment, for normal and accident conditions, as expected when operating at the increased reactor power level under EPU conditions. For areas impacted by EPU operating conditions, associated safety-related electrical equipment was reviewed in accordance with the requirements of 10 CFR 50.49 and NRC RG 1.89 (Reference 58) to ensure the existing qualification for the normal and accident conditions expected in the area where the devices are located remains adequate and the margin on the parameters complies with the recommendations of the Institute of Electrical and Electronics Engineers (IEEE) Standard (Std.) 323-1974, "IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations." The licensee stated that all equipment was evaluated and found to remain fully qualified for the post-EPU parameters with respect to radiation.

Inside Containment

The licensee's EQ for electrical equipment located inside containment is based on main steam line break (MSLB) and/or loss-of-coolant accident (LOCA) conditions and their resultant temperature, pressure, humidity, spray, and radiation consequences. The EQ of electrical equipment also includes the environment expected to exist during normal plant operation.

The NRC staff reviewed the worst case EQ enveloping accident temperature profiles (including MSLB and LOCA conditions) provided by the licensee in PUSAR Figure 2.3-1. In its response dated June 4, 2013, to the staff RAI, the licensee provided a revised drywell temperature profile showing that the EQ temperature profile bounds the PBAPS small steam line break (most limiting event for Drywell temperature) temperature profile. The staff reviewed the profile and determined that post-accident peak temperature at EPU condition will continue to be bounded by the peak temperature conditions used in the licensee's EQ analysis. The staff determined that EPU does not affect the peak temperature requirement and therefore the EQ temperature margins are maintained. In the PUSAR Figure 2.6-6, the licensee provided the bounding EPU drywell pressure profile. The licensee's evaluation determined that EQ qualification for peak pressure post-EPU will be maintained and the remaining margin will exceed the required 10% margin per IEEE Std. 323-1974.

In its letter dated January 31, 2014 (Reference 19), the licensee provided a summary of EPU impact on EQ DBA environmental parameters (Attachment 3, Enclosure A, Table 1), and it shows that the normal and accident (DBA) radiation increased by a scaling factor of approximately 1.14. Attachment 3, Enclosure A, Table 4 to this letter identifies each type of equipment and commodity included in the plant EQ program along with the EPU EQ total integrated dose (TID) for relevant plant locations and the qualification limit. The licensee stated that the EPU EQ TID is the sum of the normal dose, accident dose and 10% margin on accident dose in accordance with IEEE Std. 323-1974. The NRC staff reviewed Table 4 and finds that the EQ margins on EQ electrical equipment for EPU radiation environment will be consistent with IEEE 323-1974.

Attachment 3, Enclosure A, Table 1, to the letter dated January 31, 2014 (Reference 19), shows that the peak drywell pressure will increase from 47.8 psig to 48.7 psig. The licensee stated that all equipment and commodities were re-evaluated with respect to the EPU peak pressure of 48.7 psig. The evaluation determined that EQ qualification post-EPU was maintained and that the remaining margins exceeded the 10% margin specified in IEEE Std. 323-1974. Attachment 3, Enclosure 3, Table 2 of this letter shows that the qualification limit bounds the postulated accident pressure with margin greater than 10%.

As shown in Attachment 3, Enclosure A, Table 1, of the letter dated January 31, 2014, normal temperature, accident humidity, accident spray, and accident submergence will not change inside containment due to EPU conditions.

The NRC staff reviewed the EPU LAR and the licensee's letters dated June 4, 2013, and January 31, 2014, and verified that the effects of the proposed EPU on the EQ of electrical equipment have been adequately addressed with respect to the various parameters during and following accident and normal plant operation as discussed above. The NRC staff finds that the EPU conditions will not adversely affect the EQ of electrical equipment inside containment.

Outside Containment

The licensee's EQ for electrical equipment located outside containment is based on MSLB or other high-energy line break (HELB) conditions, whichever is limiting for each plant area and their resultant temperature, pressure, humidity, and radiation consequences. The EQ of electrical equipment also includes the environment expected to exist during normal plant operation.

The NRC staff reviewed the EPU LAR and the letters dated June 4, 2013 (Reference 5), and January 31, 2014 (Reference 19), and verified that the pressure and humidity during accident and normal plant operation remain unchanged outside containment. The staff also verified that temperature during normal plant operation remains unchanged outside containment. The licensee stated that there is no change to the accident environments of rooms with EQ electrical equipment as a result of EPU implementation. The normal temperature, pressure, and humidity conditions do not change as a result of EPU.

The licensee stated that the PBAPS EPU LAR is a constant pressure EPU, and hence the consequence of postulated HELB remains unchanged. In its letter dated January 31, 2014 (Reference 19), the licensee stated that deficiencies were noted in the reactor water cleanup (RWCU) HELB analysis and the post-LOCA heat-up analyses of the high pressure coolant injection (HPCI) pump room. The licensee stated that these analyses were re-performed using bounding values that enveloped both current (pre-EPU) and EPU operating conditions. The licensee provided a summary of its evaluation of "LOCA/HELB Temperature Evaluation Outside Containment," in Attachment 3, Enclosure A, Table 3, which shows that the qualification limits bound the postulated accident temperatures. Based on the above, the NRC staff finds that the EQ temperature limit of the electrical equipment bounds the postulated EPU accident temperature.

The radiation qualification of EQ for electrical equipment outside containment is based on the radiation dose expected to occur during normal operations plus the accident dose (i.e., TID). In PUSAR Section 2.3, the licensee stated that licensee's TID evaluation, based on the revised EPU normal and accidental radiation dose values, indicated that all EQ electrical equipment will remain fully qualified for post-EPU parameters with respect to radiation. In its letter dated January 31, 2014 (Reference 19), the licensee provided in Attachment 3, Enclosure A, Table 4, a summary of EPU EQ TID and radiation qualification limits of EQ electrical equipment and commodities. The NRC staff reviewed Table 4 and finds that the equipment located in outside containment remain qualified for post-EPU parameters with respect to radiation.

Based on the NRC staff's review of the EPU LAR, and the licensee's letters dated June 4, 2013, and January 31, 2014, the staff finds that EPU conditions will not adversely affect the EQ of electrical equipment outside containment.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the EQ of electrical equipment and concludes that the licensee has adequately addressed the effects of the proposed EPU on the environmental conditions for and the qualification of electrical equipment. 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 EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the EQ of electrical equipment.

2.3.2 Offsite Power System

Regulatory Evaluation

The offsite power system includes 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 EPU. The NRC's acceptance criteria for offsite power systems are based on final GDC-17. Specific review criteria are contained in SRP Sections 8.1 and 8.2, Appendix A to SRP Section 8.2, and Branch Technical Positions (BTPs) PSB-1 and ICSB-11.

Technical Evaluation

Grid Stability

PBAPS, Units 2 and 3, feed power to the 500 kilovolt (kV) transmission systems through two separate substations. These 500 kV substations are connected by two tie lines and are also interconnected with the Pennsylvania - New Jersey - Maryland (PJM) Interconnected system and the PECO Energy 500 kV grid system.

Each generator is connected by a 22 kV/500 kV step-up transformer to respective 500 kV Peach Bottom South and North Substations. Each substation is arranged in a two-element, breaker-and-one-half scheme. Two 500 kV transmission lines connect the substation buses resulting in a four-element, breaker-and-one-half arrangement. Four transmission lines connect the substations to the PJM Interconnection, and one line connects to the PECO Energy 500 kV system. There are three independent sources of offsite power for start-up and shutdown of the station.

The increase in thermal power translates to an increased electrical output from the station. The licensee stated that for the offsite power supply to the plant, the equipment is adequate for operation with the uprated electrical output. The changes in electrical requirements to support normal plant operation are not safety-related. The licensee determined that the increased power from the generator will have no adverse effect on the grid stability/reliability.

The licensee performed an evaluation of the grid analyses, considering the increase in electrical output, to demonstrate conformance to GDC 17. In Attachment 11 of the EPU LAR, "Grid Stability Evaluation," the licensee presented a summary of the results of the grid stability study performed by PJM and PECO to evaluate the effect of PBAPS's proposed EPU on grid reliability and stability. The licensee performed its evaluation using a system stability analysis by PJM Interconnection, the Regional Transmission Organization, and a voltage analysis by PECO Energy.

The grid events analyzed in the study were loss of the largest generator, loss of Units 2 and 3 at PBAPS, and loss of the most critical transmission line due to fault with the unit operating at full power uprate capacity consistent with SRP Section 8.2. The licensee stated that the maximum expected winter gross output would be 1370 megawatts electric (MWe) based on 0.9 lagging to 0.95 leading power factor, under EPU conditions. The maximum summer gross output of 1322.8 MWe for Unit 2, and 1321.4 MWe for Unit 3, are bounded by the winter gross output. According to the licensee, the impact study analyses performed by PJM were evaluated at 1370 MWe. The NRC staff verified that the MWe values used for the study bound expected maximum gross output for PBAPS under EPU conditions.

The licensee, in its letter dated May 24, 2013, stated that the high voltage components connecting the generator step-up transformer voltage high side to the transmission grid are a tubular bus, a section of transmission line, and disconnect switches, and the ratings of the components exceed the apparent power at EPU conditions. Based on the basis of review of PJM and PECO grid stability studies, the NRC staff determined that the transmission system will not require upgrades due to the EPU, and will not adversely impact bulk power transmission system steady-state power flow, stability, short circuit duty or power transfer. Based on the above, the NRC staff finds that reactive power will be maintained within acceptable limits analyzed in the grid studies, and the increased power from the generator will have no adverse effect on the grid stability or reliability.

Main Generator and Auxiliaries

As discussed in SE Section 1.4, both main generators will be modified for EPU. Unit 2 will have a rewound rotor, and Unit 3 will have a new rotor. In addition, the generator auxiliaries will be modified or retrofitted to accommodate the new generator rating. The modification to the generators and auxiliaries will allow the units to operate at a higher million volt amp (MVA) output. In its letter dated May 24, 2013, in response to a staff RAI, the licensee stated that the generator modification will include replacement of the six rectifiers, the existing alternator-exciter, and the automatic voltage regulator. The new rating of the main generators for each unit will be 1,530 MVA (revised from the existing 1,280 MVA). Under EPU conditions, the predicted generator maximum gross output is 1370 MWe with an expected maximum net output of 1339.4 MWe (i.e., generator gross output minus unit auxiliary transformer load).

The NRC staff reviewed the ratings of the modified generator and confirmed that they are at the maximum expected gross output for PBAPS at the proposed EPU conditions. Therefore, the staff finds that the modified main generators will support the proposed EPU conditions.

Isolated Phase Bus Duct

In PUSAR Section 2.3.2.2, the licensee stated that the isolated phase bus duct (IPBD) is being modified to increase the IPBD continuous current rating to provide for operation at EPU output (i.e., to support the main generator electrical output increase to 1530 MVA). In its May 24, 2013, response to a staff RAI, the licensee provided details on this modification. The licensee stated these modifications include replacing generator bus and associated ductwork located under the generator, replacing portions of the main bus and associated ductwork, and replacing cooling ducts to the 2C/3C main power transformer with larger ductwork to provide enhanced cooling capability for EPU operations.

The main bus of the IPBD is rated at 42,300 amps and at the CLTP, it has a rating of 33,566 amps; while at EPU load it has a maximum duty of 42,267 amps. The generator bus of the IPBD is rated at 21,200 amps and at EPU it has a design output of 21,133 amps. The delta bus of the IPBD is rated at 24,500 amps and at EPU it has a design output of 24,403 amps.

The NRC staff reviewed the information provided in the licensee's EPU LAR and the letter dated May 24, 2013, and determined that the modified IPBD will be capable of performing its intended function at EPU conditions following the planned modifications, and that the new IPBD rating bounds the maximum output of PBAPS at the EPU conditions. Therefore, the staff finds that the proposed EPU is acceptable with respect to the IPBD system.

Generator Step-Up Transformer

According to the licensee, both Units 2 and 3 generator step-up (GSU) transformers have been replaced. The GSU transformers at CLTP are loaded at 1,192 MVA and at EPU duty they will need to be loaded at 1,530 MVA. The licensee stated that the GSU transformers are rated at a maximum 1,530 MVA at 65 °C, and that under normal operations the transformers will have substantial margin due to house loads that are tapped off the IPBD prior to going through the GSU and the transformer losses.

The NRC staff reviewed the EPU LAR and finds that the existing GSU transformers are rated higher than the expected EPU electrical power output; and therefore, it will not adversely affect safe operation under EPU conditions.

Protective Relay Settings

The licensee stated in PUSAR Section 2.3.2.2 that they performed a review of protective relaying for the main generator, main step-up transformer, 500 kV transmission lines and the North and South 500 kV Substation relays. In its May 24, 2013, response to a staff RAI, the licensee stated that the generator modifications and main power transformer replacements, needed to support the EPU, required a review of the existing protective relay settings. As a result of the review and calculations performed, the licensee identified that setting changes are required for the following protective relays:

- Distance Relay
- Out of Step Relay

- Stator Loss of Coolant Relays
- Generator Loss of Field Relays
- Generator Negative Sequence Relay
- Unit Differential Relay
- Line Overcurrent Fault Detector Relays
- Line Pilot Wire Relay

The licensee stated that, based on the results of its calculation, they determined that the generator and main step-up transformer protective relaying will be adequate for EPU conditions.

In its letter dated May 24, 2013, the licensee stated that the Class 1E onsite distribution system equipment protective relays were determined to be adequate for operation at pre-EPU conditions. The licensee developed and validated the new relay settings based on the equipment ratings, and EPU modifications did not change the equipment ratings. Therefore, the licensee concluded that the protective relay settings remain adequate for EPU conditions.

Furthermore, the licensee stated that an Electrical Transient Analysis Program (ETAP) analysis showed that the onsite electrical voltage levels and the under voltage and degraded voltage settings are adequate at EPU conditions.

The NRC staff reviewed the EPU LAR and finds that the licensee has adequately addressed the impact on protective relay settings for the proposed EPU.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the offsite power system and concludes that the offsite power system will continue to meet the requirements of final GDC-17 following implementation of the proposed EPU. The offsite power system has capacity and capability to supply power to all safety loads and other required equipment. Based on the above, the NRC staff concludes that the proposed EPU will not adversely affect grid reliability or stability. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the offsite power system.

2.3.3 Alternating Current 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 final GDC-17, insofar as it requires the system to have the capacity and capability to perform its intended functions during anticipated operational occurrences and accident conditions. Specific review criteria are contained in SRP Sections 8.1 and 8.3.1.

Technical Evaluation

The AC power is provided from the transmission systems, 500 kV switchyard, and from on-site emergency diesel generators (EDGs). The AC onsite power system consists of the unit auxiliary transformers, start-up and emergency auxiliary transformers, 13.8 kV and 4.16 kV switchgear, 480 volt (V) load and motor control centers, 208/120 V distribution panels, uninterruptible power supply (UPS) systems, and EDGs. The licensee reviewed the AC system under both normal and emergency operating scenarios using a commercially available ETAP program. The software was used to analyze loads, and calculate voltage drop and short circuit current values under the scenario of the additional electric load that would result from the proposed EPU.

In PUSAR Section 2.5.6.1, the licensee stated that, due to the increase in EDG loading under EPU conditions, TS changes are required to increase the minimum fuel oil storage tank capacity from 31,000 gallons per tank to 33,000 gallons per tank. These TS changes are evaluated below in SE Section 3.23.

The licensee stated that no physical changes to the EDG fuel oil storage and transfer system are necessary. Also, to support the proposed EPU, a modification to start an additional high-pressure service water (HPSW) pump motor and a modification to provide a residual heat removal heat exchanger cross-tie are required. However, the licensee clarified that they are not adding any new HPSW pump motor; this is a modification to allow transfer of the power source to the existing HPSW divisional cross-tie motor-operated valve (MOV) in each unit (using a transfer switch) and to provide an RHR heat exchanger cross-tie MOV modification required to support EPU operation.

The licensee stated that with the exception of the starting of an additional HPSW pump motor and the RHR heat exchanger cross-tie MOV loads, the EDGs will not experience an increase in electrical equipment demand. The additional loading will remain within the EDG's 2000-hour (3000 kilowatt (kW)) ratings. In its May 24, 2013, response to an NRC staff RAI, the licensee provided loading condition data in a table format to show the peak load per time period (CLTP and EPU conditions) for each of the four EDGs. The staff verified the EDG loadings in the licensee's response and finds that the changes in the EDG loads remain bounded by the 2000-hour rating of the EDGs.

In PUSAR Table 2.3-2, "Offsite Electrical Equipment Ratings and Margins," the licensee indicated that the start-up and emergency auxiliary transformers have an increased loading from 45.4 MVA to 48.3 MVA as a result of the EPU. The NRC staff confirmed that the increased loading will remain within each transformer's rating (50 MVA), with adequate margin. In its May 24, 2013, response to a staff RAI, the licensee stated that the unit auxiliary transformers have been evaluated for EPU conditions and no modifications were found to be required.

In PUSAR Section 2.3.3.2, the licensee stated that the analytical electrical system computer model developed for PBAPS updated the main power transformer size to reflect the recent change of main power transformers and the proposed changes to main generators and condensate pumps. In its May 24, 2013, response to a staff request for additional information, the licensee stated that the safety-related buses are rated for 8,646 kilovolt-ampere (KVA) while the evaluated worst-case bus loading is 3,054 KVA for EPU conditions. Furthermore, the ETAP model was used to ensure that the equipment is within the short circuit ratings and that the fault currents and momentary and interrupting margins are within equipment ratings.

Based on this evaluation, the NRC staff concludes that the AC onsite power system remains adequate and has sufficient capacity to support all required loads for safe shutdown, to maintain a safe shutdown condition, and to operate the required equipment following postulated accidents.

In Attachment 9, "Planned Modifications to Support EPU," to the EPU LAR, the licensee stated that the six condensate pumps will have their impellers upgraded and will be receiving larger replacement motors. These upgrades will be increasing the pump head at EPU flow rates. In its May 24, 2013, response to a staff RAI, the licensee provided data in table format on the new condensate pump motors. The current 4500 horsepower (HP) condensate pump motors will be replaced by 5000 HP motors and the loading will increase from 4012 HP to 4183 HP under EPU conditions. The licensee's EPU plant electrical analysis was performed using the bounding value of 5000 HP for the replacement condensate pump motors. Additionally, the licensee stated in PUSAR Section 2.3.3.2 that detailed design of the replacement condensate pumps will address the revised relay settings to maintain selective coordination and adequate cable sizing.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the AC onsite power system and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system's functional design. The NRC staff further concludes that the AC onsite power system will continue to meet the requirements of final GDC-17 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the AC onsite power system.

2.3.4 Direct Current 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 final GDC-17, insofar as it requires the system to have the capacity and capability to perform its intended functions during anticipated operational occurrences and accident conditions. Specific review criteria are contained in SRP Sections 8.1 and 8.3.2

Technical Evaluation

The DC power system is composed of station batteries, battery chargers, and the DC distribution system. It provides DC power to motive, control, instrumentation and other DC loads. As discussed in PUSAR Section 2.3.4, the only effect to the DC power system, due to the proposed EPU, is the operation of the HPSW motor circuit breaker's spring charging motor. This operation is needed to support the RHR heat exchanger cross-tie modification.

The current large break LOCA/LOOP analysis scenario includes the closing of a single HPSW breaker. However, for the proposed EPU, an additional HPSW breaker is required to close. As noted above, this results in the operation of an additional spring charging motor load. As such, the DC power loading is changed. In its letter dated May 24, 2013, the licensee stated that the current Class 1E battery capacity margin is 4.86%. Due to the additional spring charging motor load, the Class 1E battery capacity margin will be reduced to 4.78% at EPU conditions. The Class 1E battery capacity margin bounds the additional spring charging motor load resulting from the operation of the HPSW motor circuit breaker.

Conclusion

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

2.3.5 Station Blackout

Regulatory Evaluation

Station blackout (SBO) refers to a complete loss of AC electric power to the essential and nonessential switchgear buses in a nuclear power plant. SBO involves the LOOP concurrent with a turbine trip and failure of the onsite emergency AC power system. SBO does not include the loss of available AC power to buses fed by station batteries through inverters or the loss of power from "alternate ac sources" (AACs). The NRC staff's review focused on the impact of the proposed EPU on the plant's ability to cope with and recover from an SBO event for the period of time established in the plant's licensing basis. The NRC's acceptance criteria for SBO are based on 10 CFR 50.63. Specific review criteria are contained in SRP Sections 8.1 and 8.4, and other guidance provided in Matrix 3 of RS-001.

Technical Evaluation

As discussed in PUSAR Section 2.3.5, the licensee re-evaluated SBO requirements using the guidelines of Nuclear Management and Resource Council, Inc. (NUMARC) NUMARC 87-00, "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors" (Reference 59) and Regulatory Guide 1.155, "Station Blackout" (Reference 60). The plant followed the AAC approach for calculating the coping period, where the plant uses equipment that is capable of being electrically isolated from the preferred offsite and emergency onsite AC power sources. The plant's current licensing basis is for an 8-hour coping duration. Therefore, PBAPS must meet the SBO requirements for at least 8 hours.

The licensee stated that PBAPS is able to show satisfactory response to an SBO event by satisfying the criteria used in assessing the major characteristics of the following:

- Condensate inventory for decay heat removal;
- Class 1E battery capacity;
- Compressed gas/air capacity;
- Effects of loss of ventilation; and,
- Containment isolation.

Each of the above characteristics is discussed below.

Condensate Inventory for Decay Heat Removal

The licensee's SBO evaluation for EPU conditions evaluated the condensate inventory needed for decay heat removal. The evaluation showed a need to credit additional condensate storage tank (CST) inventory for reactor core isolation cooling (RCIC) and high-pressure coolant injection (HPCI) use. The additional inventory needed for EPU conditions was evaluated to be less than 1% over the inventory needed under CLTP conditions. The licensee stated that the EPU SBO total inventory required is approximately 94,570 gallons during the coping period. This value is well within the dedicated usable CST volume following EPU of 100,722 gallons (Reference 18).

In Attachment 4 to its letter dated October 15, 2013, the licensee provided further details to demonstrate that a CST volume of 94,570 gallons is the inventory required for the PBAPS SBO coping period of 8 hours. The licensee stated that the containment response to SBO, under EPU conditions, was performed using the NRC-accepted SHEX computer code. The analysis initial conditions and key input parameters were provided in Table SRXB 30-1 in Attachment 4 to the letter dated October 15, 2013. The licensee noted that PUSAR Table 2.3-4 provides the PBAPS SBO sequence of events. At the onset of the SBO event, RCIC and HPCI are the only makeup water sources to maintain reactor water level. RCIC and HPCI initially take suction from the CST. The analysis assumes that HPCI is secured by an operator 30 minutes into the event, and RCIC operation continues to maintain reactor water level. RCIC suction is transferred to the suppression pool just prior to the suppression pool volume reaching 138,015 cubic feet. This ends the use of the CST for the SBO event. Figure SRXB 30-1 in Attachment 4 to the letter dated October 15, 2013, provided a plot of the SBO analysis results with respect to CST usage. The plot supports the licensee's conclusion that the CST volume needed for SBO at EPU conditions is 94,570 gallons.

Since the licensee's evaluation reflects the systems drawing from CST based on the SBO sequence of events, and since the evaluation was performed using the SHEX computer code, which is commonly used for BWR SBO analysis, the NRC staff determined that the licensee's SBO evaluation was acceptable for determining the minimum required CST volume.

Class 1E Battery Capacity

The licensee performed an evaluation to show that Class 1E battery capacity is adequate to support heat removal during SBO for the required coping duration. In Attachment 3 to its letter dated October 15, 2013, the licensee stated that the PBAPS SBO licensing basis includes an 8-hour coping duration and requires the availability of an AAC power source within 1-hour of the SBO event. For the first hour, the AC safe shutdown loads are powered through the batteries via an inverter and for the remaining 7 hours they are powered from the AAC power supply. The NRC staff verified that the PBAPS Class 1E batteries and AAC power source will have adequate capacity and capability to support SBO loads, at EPU conditions, for the entire SBO coping duration consistent with RG 1.155 and NUMARC 87-00.

Compressed Gas/Air Capacity

The licensee performed an evaluation to determine if the plant air-operated valves required for decay heat removal have sufficient compressed gas capacity or can be automatically or manually operated during SBO events for the required coping duration of 8 hours for EPU conditions. In Attachment 4 to its letter dated May 24, 2013, the licensee stated that the total number of safety relief valve (SRV) actuations, automatic and manual, increased from 107 for CLTP conditions to 109 for EPU conditions. The licensee stated that the installed compressed gas capacity provides for 200 SRV cycles and design leakage over 7 days. Based on this information, the NRC staff finds that PBAPS has adequate compressed air capacity, for an SBO event under EPU conditions, to perform emergency reactor pressure vessel depressurization.

Effects of Loss of Ventilation

As discussed in PUSAR Section 2.3.5, the license evaluated the following areas for the effects of loss of ventilation since they contain equipment necessary to cope with an SBO event: control room and cable spreading room, battery room, switchgear room/inverter room, drywell, RCIC room, and HPCI room. The licensee provided additional information on this evaluation in Attachment 4 to its letter dated May 24, 2013. The licensee concluded that equipment operability inside the drywell is maintained because the SBO environment is milder than the existing design and qualification bases. The licensee further concluded that, outside the drywell, EPU does not impact the heat loads and resulting room temperatures. The NRC staff finds that the licensee has adequately addressed the effects of loss of ventilation for an SBO event under EPU conditions.

Containment Isolation

As discussed in PUSAR Section 2.3.5, the licensee evaluated containment isolation capability for an SBO event under EPU conditions. Based on its evaluation, the licensee stated that containment isolation capability is not adversely affected by the SBO event for EPU. Furthermore, as discussed in PUSAR Section 2.6.1.3, "Containment Isolation," the system designs for containment isolation are not affected for EPU. The NRC staff finds that the licensee has adequately addressed containment isolation capability for an SBO event under EPU conditions.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the plant's ability to cope with and recover from an SBO event for the period of time established in the plant's licensing basis. The NRC staff concludes that the licensee has adequately evaluated the effects of the proposed EPU on SBO and demonstrated that the plant will continue to meet the requirements of 10 CFR 50.63 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed 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 EPU to ensure that the systems and any changes necessary for the proposed EPU are adequately designed such that the systems continue to meet their safety functions. The NRC staff's review was also conducted to ensure that failures of the systems do not affect safety functions. The NRC's acceptance criteria related to the quality of design of protection and control systems are based on 10 CFR 50.55a(a)(1), 10 CFR 50.55a(h), final GDC-19 and draft GDCs 1, 12, 13, 14, 15, 19, 20, 22, 23, 25, 26, 40, and 42. Specific review criteria are contained in SRP Sections 7.0, 7.2, 7.3, 7.4, 7.7, and 7.8.

Technical Evaluation

The licensee addressed instrumentation and controls in Section 2.4 of the PUSAR and in Attachments 1 and 14 to the EPU LAR, as supplemented by information provided in Attachment 5 to Supplement 3 to the EPU LAR (Reference 4). The NRC staff review focused on the suitability of the existing instruments and settings, as discussed in SE Section 2.4.1.1 and the instrument setpoint methodology, as discussed in SE Section 2.4.1.2.

2.4.1.1 Suitability of Existing Instruments and Settings

For the proposed EPU, the licensee evaluated the existing instruments of the affected nuclear steam supply systems and balance-of-plant (BOP) systems to determine their suitability for the revised operating ranges of the affected process parameters.

Where operation at EPU conditions affected safety analysis limits, the licensee verified that the acceptable safety margin continued to exist under all EPU conditions. The following instruments and settings were not affected because they are expressed in terms of percent rated thermal power (RTP).

Instrument/Parameter	Description
Reactor Protection System - Allowable Value for Average Power Range Monitor (APRM)	The current TS allowable value (AV) for the APRM neutron flux - high setdown function is ≤ 15% RTP. The proposed EPU does not modify this value. As discussed in PUSAR Section 2.4.1.3.6, no specific safety analyses take direct credit for this function.

Instrument/Parameter	Description
Neutron Flux - High Setdown (TS Table 3.3.1.1-1, APRM Function 2.a)	This function indirectly ensures that reactor power does not exceed the rescaled 23% RTP thermal limit monitoring value (see SE Section 3.3) before the Mode Switch is placed in "RUN." As shown in PUSAR Table 2.4-1, the current analytical limit (AL) for this function is 17.3% RTP. The AL does not change for the proposed EPU. As such, no change is needed to the AV.
Reactor Protection System - Allowable Value for APRM Neutron Flux – High (TS Table 3.3.1.1-1, APRM Function 2.c)	The current TS AV for the APRM neutron flux - high function is 119.7%. The proposed EPU does not modify this value. This function provides a reactor scram to protect against fast reactivity transients. As shown in PUSAR Table 2.4-1, the current AL for this function is 122.0% RTP. The AL does not change for the proposed EPU. As such, no change is needed to the AV. As discussed in Attachment 1 to the EPU LAR, the APRMs will be re-calibrated to read the new uprated level and the APRM high flux scram, expressed in units of percent licensed power, will not change.
Control Rod Block Instrumentation (SR 3.3.2.1.2, SR 3.3.2.1.3, SR 3.3.2.1.6 and note f of TS Table 3.3.2.1-1)	As discussed in Attachment 1 to the EPU LAR, for these items, the % RTP is unchanged in terms of percent power (% RTP) for EPU. SR 3.3.2.1.2, SR 3.3.2.1.3, SR 3.3.2.1.6, and Table 3.3.2.1-1 note (f) all refer to the requirement of ≤ 10% RTP. The rod worth minimizer (RWM) low power setpoint (LPSP) is unchanged in terms of percent power for EPU. The LPSP defines the power level below which the RWM is required. Maintaining this function in effect until 10% RTP will result in a larger RWM range in terms of absolute power; therefore, not revising this setpoint is conservative for EPU.
Control Rod Block Instrumentation (TS 3.3.2.1, SR 3.3.2.1.4 notes a, b, and c)	As discussed in Attachment 1 to the EPU LAR, the AL associated with the analytical value power levels for the various ranges (Low Power Range, Intermediate Power Range, and High Power Range) for rod block monitor operability are unchanged in terms of percent power for EPU; thus no setpoint change is required. This is consistent with the CLTR.

In addition, as discussed in PUSAR Section 2.4.1.2, several BOP system instrument and control devices will be recalibrated and rescaled, as needed, to accommodate the proposed EPU. In particular, the pressure control system, turbine steam bypass system, feedwater control system and leak detection system that are part of BOP will be modified to accommodate the EPU. However, these systems are non-safety related and thus they are generically dispositioned by the CLTR.

Based upon the information provided by the licensee, the NRC staff concludes that the instruments identified above, with the noted modifications, provide reasonable assurance that their intended functions will be met at EPU conditions. The licensee will make these noted modifications to accommodate the revised process parameters affected by the EPU. Discussion of instrumentation and parameter changes that modify the PBAPS TSs for the proposed EPU is provided in Section 3.0 of this SE.

2.4.1.2 Instrument Setpoint Methodology

As discussed in Attachment 14 to the EPU LAR, the instrument setpoint methodology currently implemented at PBAPS is based on GE Nuclear Energy, "General Electric Instrument Setpoint Methodology," NEDC-31336P-A (Reference 50). This methodology is procedurally-controlled and performed only by qualified personnel.

With respect to setpoint changes needed due to the proposed EPU, PUSAR Section 2.4.1.3 stated that:

> Increases in the core thermal power and steam flow affect some instrument setpoints. These setpoints are adjusted to maintain comparable differences between system settings and actual limits, and reviewed to ensure that adequate operational flexibility and necessary safety functions are maintained at the EPU RTP level. Where the power increase results in new instruments being employed, an appropriate setpoint calculation is performed and TS and/or Technical Requirements Manual (TRM) changes are implemented, as required.
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During a public meeting on December 7, 2011 (Reference 51), the NRC staff requested that the licensee provide a sample calculation for a setpoint impacted by EPU. The licensee provided a sample calculation for the APRM Simulated Thermal Power - High setpoint change in Enclosure 14a to Attachment 14 to the EPU LAR. A review of the TS changes associated with this function, for the proposed EPU, is discussed in SE Section 3.8.4. The NRC staff's review of other setpoint changes needed due to the proposed EPU is included in the applicable sub-sections of SE Section 3.0.

Conclusion

The NRC staff has reviewed the licensee's application related to the effects of the proposed EPU on the functional design of the reactor trip system, ESFAS, safe shutdown system, and control systems. The NRC staff concludes that the licensee has adequately addressed the effects of the proposed EPU on these systems and that the changes that are necessary to achieve the proposed EPU are consistent with the plant's design basis. The NRC staff further concludes that the systems will continue to meet the requirements of 10 CFR 50.55a(a)(1), 10 CFR 50.55(a)(h), final GDC-19 and draft GDCs 1, 12, 13, 14, 15, 19, 20, 22, 23, 25, 26, 40, and 42. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to instrumentation and controls.

2.5 Plant Systems

The licensee addressed the various plant systems discussed below in Section 2.5 of the PUSAR.

2.5.1 Internal Hazards

2.5.1.1 Flooding

2.5.1.1.1 Flood Protection

Regulatory Evaluation

The NRC staff conducted a review in the area of flood protection to ensure that SSCs important to safety are protected from flooding. The NRC staff's review covered flooding of SSCs important to safety from internal sources, such as those caused by failures of tanks and vessels. The NRC staff's review focused on increases of fluid volumes in tanks and vessels assumed in flooding analyses to assess the impact of any additional fluid on the flooding protection that is provided. The NRC's acceptance criteria for flood protection are based on draft GDC-2. Specific review criteria are contained in SRP Section 3.4.1.

Technical Evaluation

Operation at the uprated power level may affect liquid pressure, temperature, and flow rates within certain high energy piping systems, including the main feedwater (FW) system. However, operation at the uprated power should not affect inventory in medium energy systems. The licensee evaluated components and equipment required for safe shutdown of the reactor for the effects of flooding from breaks and cracks in high energy lines. The evaluations verified that the licensee could safely shut down the plant, assuming a concurrent single active failure in systems necessary to mitigate the consequences of the postulated component failure. The licensee evaluated plant flooding caused by internal piping failures in the FW system for changes in flood mitigation capacity because of the proposed EPU. The licensee evaluated the flooding with the conservative basis that the entire hotwell volume releases into the main steam tunnel then drains to the reactor building. Because the EPU does not change to the existing hotwell inventory, the flood levels in the reactor building from a FW break remain unchanged. As a result, the floor draining systems and flood barriers do not require modification. Therefore, the EPU does not affect the remaining systems evaluated because the current flooding analyses bounds those systems. According to the licensee's evaluation, the EPU does not affect internal flooding caused by postulated failures in high-energy piping systems.

The licensee evaluated components and equipment required for safe shutdown of the reactor for the effects of flooding from breaks and cracks in medium energy lines. The licensee verified that system design limits used as input to the moderate energy line break (MELB) flooding analyses do not change because of the EPU. As a result, the flow rates and/or the system inventories of analyzed moderate energy piping systems do not increase for EPU. Therefore, operation at the uprated power does not affect the ability of the plant to cope with effects of flooding from MELBs. EPU does not introduce new MELB locations and does not introduce or move safety-related equipment with the exception of new MOVs to be added with the residual heat removal (RHR) heat exchanger cross-tie modification. The licensee will seal appropriately any new penetrations in flood barriers added by the RHR heat exchanger cross-tie modification to maintain integrity of the barrier against postulated flooding consistent with the current design of the barrier.

Because the current flooding analysis bounds postulated flooding at the uprated power, PBAPS will still meet the criteria in draft GDC-2. Therefore, the NRC staff has reasonable assurance that SSCs important to safety will continue to be protected from flooding during operation at the uprated power.

Conclusion

The NRC staff has reviewed the proposed changes in fluid volumes in tanks and vessels for the proposed EPU. The NRC staff concludes that SSCs important to safety will continue to be protected from flooding and will continue to meet the requirements of draft GDC-2 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to flood protection.

2.5.1.1.2 Equipment and Floor Drains

Regulatory Evaluation

The function of the equipment and floor drainage system (EFDS) is to assure that waste liquids, valve and pump leak-offs, and tank drains are directed to the proper area for processing or disposal. The EFDS is designed to handle the volume of leakage expected, prevent a backflow of water that might result from maximum flood levels to areas of the plant containing safety-related equipment, and protect against the potential for inadvertent transfer of contaminated fluids to an uncontaminated drainage system. The NRC staff's review of the EFDS included the collection and disposal of liquid effluents outside containment. The NRC staff's review focused on any changes in fluid volumes or pump capacities that are necessary for the proposed EPU and are not consistent with previous assumptions with respect to floor drainage considerations. The NRC's acceptance criteria for the EFDS are based on draft GDC-2 insofar as it requires the EFDS to be designed to withstand the effects of earthquakes and to be compatible with the environmental conditions (flooding) associated with normal operation, maintenance, testing, and postulated accidents (pipe failures and tank ruptures). Specific review criteria are contained in SRP Section 9.3.3.

Technical Evaluation

As discussed in SE Section 1.3, the EPU LAR application was prepared following the guidelines contained in NRC-approved General Electric (GE) Licensing Topical Report (LTR) NEDC-33004P-A, "Constant Pressure Power Uprate," (Reference 20). The constant pressure power uprate (CPPU) LTR, is commonly referred to as the "CLTR." Section 8.1 of the CLTR addresses the effect of CPPU on the liquid and solid waste management. The CLTR states that increased power levels and steam flow result in the generation of slightly higher levels of liquid radwaste, but the power uprate does not affect the floor drain collector subsystem and the waste collector subsystem operation or equipment performance.

The licensee evaluated the EFDS to ensure any EPU-related liquid radwaste increases can be processed. The licensee determined that neither subsystem is expected to experience a large increase in the total volume of liquid and solid waste during operation at the uprated power. Therefore, the current design of the PBAPS equipment and floor drains inside and outside of containment has sufficient capacity to handle added liquid increases expected during operation at the uprated power. The drainage systems backflow at maximum flood levels and infiltration of radioactive water into non-radioactive water drains does not change because of the EPU. In addition, the drainage systems design capability to withstand the effects of earthquakes and to be compatible with environmental conditions does not change because of EPU. Because the current EFDS is capable of handling the slight increase in liquid waste inventory, the licensee does not plan to make structural changes to the EFDS.

Based on the above, the NRC staff finds that there is reasonable assurance that the EFDS will continue to meet the criteria in draft GDC-2 following implementation of the EPU.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the EFDS and concludes that the licensee has adequately accounted for the plant changes resulting in increased water volumes and larger capacity pumps or piping systems. The NRC staff concludes that the EFDS has sufficient capacity to: (1) handle the additional expected leakage resulting from the plant changes; (2) prevent the backflow of water to areas with safety-related equipment; and (3) ensure that contaminated fluids are not transferred to non-contaminated drainage systems. Based on this, the NRC staff concludes that the EFDS will continue to meet the requirements of draft GDC-2 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the EFDS.

2.5.1.1.3 Circulating Water System

Regulatory Evaluation

The circulating water system (CWS) provides a continuous supply of cooling water to the main condenser to remove the heat rejected by the turbine cycle and auxiliary systems. The NRC staff's review of the CWS focused on changes in flooding analyses that are necessary due to increases in fluid volumes or installation of larger capacity pumps or piping needed to accommodate the proposed EPU. Specific review criteria are contained in SRP Section 10.4.5.

Technical Evaluation

The licensee evaluated the performance of the CWS for operation at the uprated power in relation to the original design capacity of the CWS and the cooling tower system over the actual range of circulating water inlet temperatures. The licensee determined that the CWS and heat sink are adequate for EPU operation. However, circulating water inlet temperatures may require load reductions, based on condenser hotwell limitations, but the licensee anticipates this to be an infrequent occurrence. The evaluation of the CWS at EPU power indicates sufficient system capacity to ensure that the plant maintains adequate condenser backpressure. The licensee is not modifying the CWS for EPU operation. As a result, the EPU does not affect the sources of flooding and protection measures in the CWS. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the CWS.

Conclusion

The NRC staff has reviewed the licensee's assessment of the CWS. Based on the review, as described above, the staff concludes there is reasonable assurance that the CWS will be able to perform its existing design basis functions for the proposed EPU. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the CWS.

2.5.1.2 Missile Protection

2.5.1.2.1 Internally Generated Missiles

Regulatory Evaluation

The NRC staff's review concerns missiles that could result from in-plant component overspeed failures and high-pressure system ruptures. The NRC staff's review of potential missile sources covered pressurized components and systems, and high-speed rotating machinery. The NRC staff's review was conducted to ensure that safety-related SSCs are adequately protected from internally generated missiles. In addition, for cases where safety-related SSCs are located in areas containing non-safety-related SSCs, the NRC staff reviewed the non-safety-related SSCs to ensure that their failure will not preclude the intended safety function of the safety-related SSCs. The NRC staff's review focused on any increases in system pressures or component overspeed conditions that could result during plant operation, anticipated operational occurrences, or changes in existing system configurations such that missile barrier considerations could be affected. The NRC's acceptance criteria for the protection of SSCs important to safety against the effects of internally generated missiles that may result from equipment failures are based on draft GDC-40. Specific review criteria are contained in SRP Sections 3.5.1.1 and 3.5.1.2.

Technical Evaluation

Section 7.1 of the CLTR states that the increase in steam flow can change the previous missile avoidance and protection analysis. Per the CTLR, the only safety-related evaluation necessary, associated with turbine operation at the uprated power level, is a plant-specific turbine-generator missile avoidance and protection analysis. The CLTR states that an evaluation is required for turbine rotors with shrunk-on wheels.

As discussed in PUSAR Section 2.5.1.2.1, in support of the proposed EPU, the licensee will replace the high-pressure (HP) and low-pressure (LP) turbine rotors with integral, non-shrunk on wheels. These integral rotors are not considered a source for potential missile generation for EPU for the slight increase in entrapped energy. Even though a separate rotor analysis is only needed for rotors with shrunk-on wheels (i.e., per CLTR Section 7.1), the licensee evaluated the new LP turbine rotors to verify that the probability of turbine missile generation remains within the limits of RG 1.115, "Protection Against Low-Trajectory Turbine Missiles" (Reference 52).

The licensee will convert the PBAPS HP and LP turbines to a single forging and welded design, respectively, and confirm the trip values. The LP rotor conversion from built-up to the welded design significantly increases total rotor inertia. This large increase in inertia slows the acceleration rate of the machine should a load rejection event occur. The estimated peak speed following a full load rejection remains unchanged at the uprated power level. As a result, the licensee will not need to adjust the design setting of the mechanical trip. The mechanical trip setting will remain at a maximum of 109.3% of rated speed. In addition, the calculated overspeed (approximately 115% of rated speed) will not be changed.

The spent fuel pool (SFP) system is located in the reinforced concrete reactor building. Dynamic effects and missiles that might result from plant equipment failures have not changed with respect to the plant's current design.

Increased system pressures and equipment overspeed during operation at the uprated power level should not result in an increase in the generation of internally generated missiles. In addition, operation at the uprated power level should not require any changes in equipment configurations that could change the effect of internally generated missiles on safety-related or non-safety related equipment. As a result, the NRC staff finds that there is reasonable assurance that PBAPS will continue to meet the requirements of draft GDC-40 with respect to SSCs important to safety being protected from internally generated missiles.

Conclusion

The NRC staff has reviewed the changes in system pressures and configurations that are required for the proposed EPU and concludes that SSCs important to safety will continue to be protected from internally generated missiles and will continue to meet the requirements of draft GDC-40, following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to internally generated missiles.

2.5.1.2.2 Turbine Generator

Regulatory Evaluation

The turbine control system, steam inlet stop and control valves, low pressure turbine steam intercept and inlet control valves, and extraction steam control valves control the speed of the turbine under normal and abnormal conditions, and are thus related to the overall safe operation of the plant. The NRC staff's review of the turbine generator focused on the effects of the proposed EPU on the turbine overspeed protection features to ensure that a turbine overspeed condition above the design overspeed is very unlikely. The NRC's acceptance criteria for the turbine generator are based on draft GDC-40 and relates to protection of SSCs important to safety from the effects of turbine missiles by providing a turbine overspeed protection system (with suitable redundancy) to minimize the probability of generating turbine missiles. Specific review criteria are contained in SRP Section 10.2.

Technical Evaluation

Section 7.1 of the CLTR addresses the effects of power uprates on the turbine-generator (T-G). The CLTR states that the increase in thermal energy and steam flow from the reactor translates to an increased electrical output from the station by the T-G and that modifications are usually required to support the power uprate. The T-G is required for normal plant operation and is not safety-related. However, over-speeding of the turbine affects the overall safe operation of the plant. The licensee evaluated the T-G overspeed protection systems to ensure that adequate protection is provided for EPU conditions.

As discussed in PUSAR Section 2.5.1.2.2, the turbine and generator are designed with a maximum flow-passing capability and generator output in excess of current rated conditions, to ensure that the current rated steam-passing capability and generator output is achieved. The licensee refers to this excess design capacity as the "flow margin." The flow margin ensures that the turbine and generator meet rated conditions for continuous operating capability with allowances for variation in flow coefficients, manufacturing tolerances, and other variables that may adversely affect the flow-passing capability of the plant.

The main turbine currently operates with a design flow margin of 3.4%. The current rated throttle steam flow is 14.4 million pounds-mass per hour (Mlbm/hr) at a throttle pressure of 994 pounds per square inch absolute (psia). At the EPU rated thermal power and reactor dome pressure of 1050 psia, the licensee stated that the turbine will operate at an increased rated throttle steam flow of 16.24 Mlbm/hr and at a throttle pressure of 964.2 psia. The existing high-pressure turbine (HPT) is not capable of passing this flow. As such, the licensee will replace the existing HPT prior to the EPU with one designed for EPU flow conditions. The new HPT section design will allow adequate throttle flow margin for operation at the uprated power level.

The licensee will replace the low pressure turbine (LPT) rotors and inner casings prior to the EPU. The LPT design will include blades manufactured from corrosion resistant materials. The design of the rotating and the stationary parts provides resistance to stress-corrosion cracking.

The licensee evaluated the natural frequency of the replacement LPT and found it to be acceptable. The licensee stated that the new turbine design excludes natural frequencies that are coincident with operating resonance frequencies. The licensee also performed lateral and torsional vibration analyses for EPU conditions to demonstrate that increased steam flow will not cause excessive vibration on the LPT and the generator.

The licensee evaluated generator components to identify the impact of the proposed EPU. The generator was originally rated at 1280 million volt amps (MVA), which resulted in a rated electrical output (gross) of 1159.5 megawatts-electric (MWe) at a power factor (PF) of 0.906 and a reactive power of 542 million volt amps reactive (MVAR). The licensee determined that operating at the uprated power will require an increase in generator rating to 1530 MVA. As discussed in SE Section 1.2, the proposed EPU power level represents an increase of approximately 20 percent above the original licensed thermal power (OLTP) level. The licensee stated that the modified generator will support the EPU of 120% OLTP with ratings of 1408 MWe at 0.920 PF for PBAPS, Unit 2, and 1377 MWe at 0.900 PF for Unit 3.

The licensee conducted a specific missile generation study for EPU power operation. The probability of LPT missile generation was determined to be 0.97×10^{-6} per year per unit. The licensee concluded that the probability of a missile because of a runaway overspeed event is acceptable for EPU.

The licensee stated that the overspeed calculation compares the entrapped steam energy contained within the turbine and the associated piping, after the stop valves trip, and the sensitivity of the rotor train for the capability of overspeeding. The entrapped energy increases for EPU conditions. The hardware modification design and implementation process establishes the overspeed trip settings to provide protection for a turbine trip.

As discussed above, to compensate for the increased EPU steam flow, the licensee will upgrade the HP and LP turbines, as well as the generator. The licensee concluded that the EPU turbine design does not result in increases in system pressures, configurations, or equipment overspeed that would affect the evaluation of internally generated missiles on safety-related or non-safety related equipment.

Based on the above, the NRC staff finds that the licensee has adequately evaluated and addressed the potential impact of the proposed EPU on the capability to prevent turbine overspeed.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the turbine generator and concludes that the licensee has adequately accounted for the effects of changes in plant conditions on turbine overspeed. The NRC staff concludes that the turbine generator will continue to provide adequate turbine overspeed protection to minimize the probability of generating turbine missiles and will continue to meet the requirements of draft GDC-40 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the turbine generator.

2.5.1.3 Pipe Failures

Regulatory Evaluation

The NRC staff conducted a review of the plant design for protection from piping failures outside containment to ensure that: (1) such failures would not cause the loss of needed functions of safety-related systems; and (2) the plant could be safely shut down in the event of such failures. The NRC staff's review of pipe failures included high and moderate energy fluid system piping located outside of containment. The NRC staff's review focused on the effects of pipe failures on plant environmental conditions, control room habitability, and access to areas important to safe control of post-accident operations where the consequences are not bounded by previous analyses. The NRC's acceptance criteria for pipe failures are based on draft GDC-40, insofar as it requires that protection be provided for ESFs against the dynamic effects that might result from plant equipment failures. Specific review criteria are contained in SRP Section 3.6.1.

Technical Evaluation

High-Energy Lines

As discussed in PUSAR Sections 2.2.1 and 2.5.1.3, the licensee evaluated increased piping stresses in high-energy piping outside containment against existing line break criteria to identify any potential new break locations. The licensee's evaluation was based on the criteria contained in Section A.10.2 of the PBAPS UFSAR. The UFSAR criteria were established based on a meeting between the licensee and the AEC/NRC staff in January 1973. The results of that evaluation determined that there are no new postulated high-energy line break (HELB) locations outside containment due to operation at EPU conditions.

As also discussed in PUSAR Sections 2.2.1 and 2.5.1.3, the licensee evaluated existing HELB locations outside containment that are affected by the proposed EPU. This evaluation reviewed steam line breaks and liquid line breaks as discussed below.

With respect to steam lines, the licensee stated that the proposed EPU has no effect on the steam pressure or enthalpy at the postulated break locations. As such, the licensee also stated that the proposed EPU has no effect on the mass and energy releases from a HELB in a steam line.

With respect to liquid lines, EPU may increase sub-cooling in the reactor vessel, which may lead to increased break flow rates for liquid line breaks. The license stated that, for PBAPS, the increase in vessel sub-cooling could affect the reactor water cleanup (RWCU) system line break analysis. In addition, the licensee stated that operation at EPU conditions requires an increase in main steam and feedwater (FW) flows, which results in an increase in FW system pressures. This increase in pressure may lead to increased break flow rates for FW line breaks. Based on these considerations, the licensee evaluated mass and energy releases under EPU conditions for HELBs in the RWCU and FW systems.

With respect to the RWCU evaluation, the licensee stated that new compartment pressure and temperature responses from the increase in RWCU line break mass and energy releases were calculated. Structural effects of the new peak pressures were reviewed and found to be acceptable.

The FW system evaluation concluded that the minor changes in FW line break mass and energy releases will not challenge the bases for the HELB analysis of record disposition which concludes that the effects of a FW line break are bounded by the effects of postulated main steam line breaks.

The evaluations of HELBs outside containment also included a review of pipe whip and jet impingement loads. The licensee determined that the EPU pipe wipe and jet impingement loads are bounded by the current licensing basis loads.

Moderate-Energy Lines

As discussed in PUSAR Section 2.5.1.3.2, for moderate-energy pipe breaks, operation at the uprated power does not change the system design limits the licensee used as input to the moderate energy line crack (MELC) flooding analyses. The licensee stated that because the EPU does not affect the PBAPS MELC mass releases and environmental conditions (pressures and temperatures), there is no adverse impact to post-MELC control room habitability or to access to areas important to safe control of post-accident operations.

Environmental Conditions

As discussed in PUSAR Section 2.3.1.3.3, the accident temperature, pressure, and humidity environments used for qualification of equipment outside containment result from a main steam line break, or other HELBs, whichever is limiting for each plant area. The values the licensee used for equipment qualification at the CLTP level bound the peak HELB temperatures and pressures under EPU conditions.

Summary

Based on the above, the NRC staff finds that the licensee has provided reasonable assurance that SSCs important to safety will be protected against the piping failures outside containment under EPU conditions.

Conclusion

The NRC staff has reviewed the changes that are necessary for the proposed EPU and the licensee's proposed operation of the plant, and concludes that SSCs important to safety will continue to be protected from the dynamic effects of postulated piping failures in fluid systems outside containment and will continue to meet the requirements of draft GDC-40 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to protection against postulated piping failures in fluid systems 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) 10 CFR 50.48 and associated Appendix R to 10 CFR Part 50, insofar as they require the development of an FPP to ensure, among other things, the capability to safely shut down the plant; (2) final GDC-3, insofar as it requires that (a) SSCs important to safety be designed and located to minimize the probability and effect of fires, (b) noncombustible and heat resistant materials be used, and (c) fire detection and fighting systems be provided and designed to minimize the adverse effects of fires on SSCs important to safety; and (3) draft GDC-4, insofar as reactor facilities shall not share systems or components unless it is shown safety is not impaired by the sharing. 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

The licensee discussed the impact of the proposed EPU, with respect to the PBAPS FPP, in Section 2.5.1.4, "Fire Protection," of the PUSAR. The licensee's evaluation concluded that the FPP will continue to meet the requirements of 10 CFR 50.48 and the intent of Appendix R to 10 CFR Part 50 following the implementation of the proposed EPU. The licensee provided additional information regarding fire protection in the following supplements to the EPU LAR: Supplement 3 (Reference 4), Supplement 8 (Reference 9), Supplement 13 (Reference 14), Supplement 17 (Reference 18), Supplement 18 (Reference 19), and Supplement 20 (Reference 75).

As discussed in PUSAR Section 2.5.1.4.1, "Fire Protection Program," the licensee evaluated the FPP, fire suppression and detection systems, and reactor and containment system responses to postulated 10 CFR Part 50, Appendix R fire events. The licensee's evaluation concluded that the proposed EPU for PBAPS met all CLTR dispositions. Specifically, the licensee determined that the following topics met the CLTR dispositions:

- Fire Suppression and Detection Systems
- Operator Response Time
- Peak Cladding Temperature
- Vessel Water Level
- Suppression Pool Temperature

The licensee stated in PUSAR Section 2.5.1.4.1 that the proposed EPU would not affect the elements of the fire protection plan related to fire suppression and detection systems, fire barriers, and fire protection responsibilities of plant personnel. The licensee also stated that the reactor and containment response to the postulated 10 CFR Part 50, Appendix R fire event was evaluated and that the results show that the peak fuel cladding temperature, reactor pressure, and containment pressures and temperatures would remain below acceptance limits. However, the Appendix R evaluation determined that modifications and procedural changes associated with the condensate storage tank (CST) would be needed to ensure that sufficient inventory is available for the EPU Appendix R scenarios that credit the CST. The CST-related changes are discussed below.

As discussed in Attachment 5 to Supplement 17 to the EPU LAR (Reference 18), each PBAPS unit has its own CST, each with a dedicated usable volume following EPU of 100,722 gallons. For the bounding Appendix R Shutdown Method analysis at EPU conditions, the maximum CST usage is approximately 154,000 gallons. Therefore, modifications and procedural changes are needed to ensure that sufficient inventory remains available for the Appendix R scenarios that credit the CST. The remainder of the condensate supply needing for mitigating the Appendix R event will be provided by gravity feeding from the refueling water storage tank (RWST) to the CST. Since there is one common RWST that supplies both units, it must be capable of simultaneously supplying both CSTs with the additional volume needed to mitigate the Appendix R event on each unit. The licensee stated that the minimum required RWST volume for the bounding Appendix R scenario is calculated to be about 142,000 gallons for a single unit or about 227,300 gallons for two units. These volumes include the RWST unusable volume, the volume required for the scenario and the additional volume in the RWST to establish adequate head to provide makeup flow. The licensee stated that the minimum volumes in the CST and

RWST will be administratively controlled. As discussed in Section 2.5.1.4.1 of the PUSAR, as part of the licensee's design configuration process, modifications associated with EPU will be assessed and assured not to adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

In Section 2.5.1.4.1 of the PUSAR, the licensee stated that, except for the changes associated with the CST, other safe shutdown systems and equipment used to achieve and maintain cold shutdown conditions do not change and, therefore, are adequate for the EPU conditions. PUSAR Section 2.5.1.4.2, "10 CFR 50 Appendix R Fire Event," states that one train of systems remains available to achieve and maintain safe shutdown conditions from either the main control room or the remote shutdown panel.

As discussed in Section 6.7 of the CLTR, the higher decay heat associated with an EPU may reduce the time available for the operator to perform the actions necessary to achieve and maintain cold shutdown conditions. In PUSAR Section 2.5.1.4.2, the licensee describes the four fire safe shutdown methods defined in the PBAPS Fire Protection Report. In Attachment 2 to Supplement 18 to the EPU LAR (Reference 19), the licensee stated that for three of the four methods (Methods A, B, and C) there is no reduction in time margin for operator actions outside of the main control room. However, the NRC staff notes that at EPU conditions, there is a 1 minute reduction in maximum operator action time for Method C within the main control room to open three safety relief valves (SRVs) of the automatic depressurization system (ADS) and initiate reactor pressure vessel (RPV) depressurization (i.e., necessary actions to achieve and maintain cold shutdown conditions). For the fourth method, Method D, the licensee stated there was a reduction in time margin for operator actions outside the main control room.

With respect to Method C, the NRC staff determined that the 1-minute reduction in time is consistent with the observation noted in the CLTR. In particular, the NRC staff reviewed the licensee's evaluation and determined that the reduction in time is associated with the time that it takes for the indicated reactor level to reach the top of active fuel (reference PUSAR Table 2.5-3). With a higher decay heat load associated with the EPU, the reduction in time is a reasonable result. In addition, the NRC staff observed that the reduction in time is 1 minute, with 26.5 minutes remaining available for the operator action within the main control room. Guidance in several sections of NUREG-0800, Chapter 15, "Transient and Accident Analysis," indicates that operator action times credited in safety analyses less than 10 minutes following event inception warrant detailed review. Since this time remains significantly greater than 10 minutes, the NRC staff further determined that the 1-minute reduction was an acceptable result. In summary, the NRC staff determined the licensee's analysis with respect to Method C was acceptable based on the following considerations: (1) the licensee's evaluation is consistent with the evaluation contained in the CLTR; (2) the reduction in manual SRV opening time is 1 minute; and (3) the new time remains significantly greater than 10 minutes.

The fourth fire safe shutdown method, Method D, "Initiate Torus Cooling and RPV Depressurization," utilizes HPCI, one SRV and one residual heat removal pump (in low pressure coolant injection, pool cooling and alternate shutdown coolant modes) to achieve plant shutdown at the alternate shutdown (ASD) panel. In Attachment 2 to Supplement 18 to the EPU LAR (Reference 19), the licensee provided the following details related to the reductions in margin for Method D:

Item	Time to	Limiting Shutdown Method	Current Available Time	EPU Available Time	Reduced Margin
1	Initiate RPV depressurization from the ASD panel without a stuck-open relief valve (SORV)	D	5 Hours (300 minutes)	3.5 Hours (210 minutes)	1.5 Hours (90 minutes)
2	Initiate suppression pool cooling (SPC) from the ASD panel with a SORV	D	4 Hours (240 minutes)	2.5 Hours (150 minutes)	1.5 Hours (90 minutes)
3	Initiate SPC from the ASD panel without a SORV	D	3 Hours (180 minutes)	2.5 Hours (150 minutes)	0.5 Hour (30 minutes)

The licensee provided justification for the above reduced time margins in Attachment 2 to Supplement 18 to the EPU LAR (Reference 19), as clarified by information provided in Supplement 20 to the EPU LAR (Reference 75). The licensee stated the reductions in margin are acceptable because the operator actions that are required can be completed in less than 2 hours (i.e., at least 30 minutes of margin over and above the EPU available time to complete the actions). The licensee stated this is based on the past operator experience in simulator training for the actual time required to complete the required actions. The licensee indicated that a review of the timeline analyses for Fire Area 25 (main control room) confirmed that no time challenges exist that would prevent completion of these actions in the required time.

The NRC staff has reviewed the licensee's justifications relating to impacts of the EPU on existing operator actions time for fire safe shutdown Method D. Because the time available for these operator manual actions is greater than the time required based on plant simulator training and past operator experience, the NRC staff has reasonable assurance that the licensee will be capable of performing required operator actions outside the main control room for the fire safe shutdown Method D under EPU conditions to achieve and maintain cold shutdown conditions.

As discussed in Attachment 2 to Supplement 3 to the EPU LAR (Reference 4), the licensee discussed the impact on operator manual actions potentially impacted due to the higher decay heat associated with an EPU. The licensee stated that the increased decay heat results in additional heat input to the torus due to reactor pressure relief via the main steam safety valves. The licensee stated that there are operator actions where torus temperature is the dominant environmental impact; however, the peak torus temperature at EPU conditions is less than was analyzed previously due to changes associated with elimination of the credit for containment accident pressure and the associated RHR cross-tie modification. As a result, the licensee concluded that EPU will not: (1) impact any required operator manual actions being performed at their designated time; nor (2) require any new operator actions to maintain hot shutdown and then place the reactor in a cold shutdown condition.

With respect to the analysis of alternate shutdown cooling under EPU conditions, the licensee stated in PUSAR Section 2.5.1.4.1 that cold shutdown is achieved within 62 hours under alternate shutdown cooling. As such, the 72-hour cold shutdown requirement, as stipulated by Appendix R, is met.

In Attachment 5 to Supplement 13 to the EPU LAR (Reference 14), the licensee stated that PBAPS does not use the fire protection system for non-fire protection activities in any design basis scenario. However, PBAPS has the potential to rely on fire protection systems for beyond design basis events such as: (1) reactor pressure vessel injection when preferred water sources are not available; (2) makeup to the spent fuel pool; (3) radiological release scrubbing; (4) direct makeup to the emergency cooling tower; and (5) external makeup to the condensate system hotwell. The licensee stated that reliance on the fire protection system for these beyond design basis uses is not affected by the EPU.

Based on its review, the NRC staff concludes that the proposed EPU does not impact current operator manual actions (except as discussed above) that will remain unchanged after EPU, nor is any new operator manual action or change in the approved fire protection operator manual actions required. The NRC staff notes that this SE does not approve any new or existing operator manual actions concerning the PBAPS, Units 2 and 3, fire safe-shutdown.

Conclusion

The NRC staff has reviewed the licensee's fire-related safe shutdown assessment and concludes that the licensee has adequately accounted for the effects of the increased decay heat on the ability of the required systems to achieve and maintain safe shutdown conditions. The NRC staff further concludes that the FPP will continue to meet the requirements of 10 CFR 50.48, Appendix R to 10 CFR Part 50, final GDC-3 and draft GDC-4 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

Regulatory Evaluation

The NRC staff's review for fission product control systems and structures covered the basis for developing the mathematical model for DBLOCA dose computations, the values of key parameters, the applicability of important modeling assumptions, and the functional capability of ventilation systems used to control fission product releases. The NRC staff's review primarily focused on any adverse effects that the proposed EPU may have on the assumptions used in the analyses for control of fission products. The NRC's acceptance criteria are based on final 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 6.5.3.

Technical Evaluation

As discussed in PUSAR Section 2.5.2.1, the standby gas treatment system (SGTS) is designed to maintain secondary containment at a negative pressure and to provide an elevated release path for the removal of fission products potentially present during abnormal conditions. By preventing the ground level release of airborne particulates and halogens, the SGTS limits off-site dose following a postulated DBA.

The licensee is not altering the SGTS component design or the filter materials for operation at the uprated power. The total (radioactive plus stable) post-LOCA iodine loading on the charcoal adsorbers increases proportionally with the increase in core iodine inventory, which increases with core thermal power. However, the licensee stated that there is sufficient charcoal mass present so that the post-LOCA iodine loading on the charcoal will remain below the guidance provided by RG 1.52 (Reference 53). The licensee further stated that [[

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GE performed two bounding analyses for the NRC-approved CLTR to evaluate decay heating in the SGTS for: (1) plants such as PBAPS that implement alternative source term (AST) in accordance with RG 1.183 (Reference 54); and (2) plants committed to RG 1.3 (Reference 55) for fission product transport. Two parameters of the PBAPS SGTS design are outside of the bounds of the GE analyses; [[ ]] However, the results of the PBAPS evaluation show that the actual charcoal loading of 0.0074 milligrams (mg) of total iodine per gram (gm) of charcoal is much less than the RG 1.52 allowable of 2.5 mg/gm. The PBAPS SGTS utilizes a deluge system, instead of a minimum cooling flow, to assure no desorption of radionuclides in the case of increased decay heating. The maximum component temperature for the PBAPS evaluation is 147.8 °F, which is below the allowable component temperature in the bounding analyses. In addition, the licensee does not credit removal capabilities of the high-efficiency particulate air (HEPA) filters and the charcoal contained in the SGTS trains with respect to the post-LOCA accident.

While decay heat from fission products accumulated within the system filters and charcoal adsorbers increases with the increase in thermal power, the manually operated deluge sub-system of the SGTS will continue to protect the system from desorption should there be a loss of system flow.

The remaining parameters in the bounding AST analysis bound the PBAPS plant-specific values.

Based on the above, the NRC staff finds that the licensee has adequately addressed the impacts of the proposed EPU with respect to fission product control systems and structures

<u>Conclusion</u>

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on fission product control systems and structures. The NRC staff concludes that the licensee has adequately accounted for the increase in fission products and changes in expected environmental conditions that would result from the proposed EPU. The NRC staff further concludes that the fission product control systems and structures will continue to provide adequate fission product removal in post-accident environments following implementation of the proposed EPU. Based on this, the NRC staff also concludes that the fission product control systems and structures will continue to meet the requirements of final GDC-60. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the fission product control systems and structures.

2.5.2.2 Main Condenser Evacuation System

Regulatory Evaluation

The main condenser evacuation system (MCES) generally consists of two subsystems: (1) the "hogging" or startup system which initially establishes main condenser vacuum; and (2) the system which maintains condenser vacuum once it has been established. The NRC staff's review focused on modifications to the system that may affect gaseous radioactive material handling and release assumptions, and design features to preclude the possibility of an explosion (if the potential for explosive mixtures exists). The NRC's acceptance criteria for the MCES are based on: (1) final GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents; and (2) final 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 anticipated operational occurrences and postulated accidents. Specific review criteria are contained in SRP Section 10.4.2.

Technical Evaluation

As discussed in PUSAR Section 2.5.2.2, the licensee is not modifying the condenser air removal system because operation at the uprated power does not adversely affect the design of the condenser air removal system. The increase in steam flow increases the heat removal requirement for the condenser. The additional power level increases the non-condensable gases generated by the reactor. The licensee uses the main condenser "hogging" and the steam jet air ejectors (SJAE) functions, which are not safety-related for normal plant operation. The licensee evaluated the following aspects of the condenser air removal system:

- Non-condensable gas flow capacity of the SJAE system;

- Capability of the SJAEs to operate satisfactorily with available dilution/motive steam flow; and

- Mechanical vacuum (hogging) pump capability to remove required non-condensable gases from the condenser at EPU start-up conditions.

The licensee stated that the physical size of the primary condenser and evacuation time are the main factors in establishing the capabilities of the vacuum pumps. These parameters do not change with EPU. Because flow rates do not change, there is no change to the holdup time in the pump discharge line routed to the main vent stack. The original design capacity of the SJAEs allows for operation at flows above those required during operation at the uprated power. As a result, the MCES design bases for PBAPS remains unchanged for operation at the uprated power. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the MCES.

Conclusion

The NRC staff has reviewed the licensee's assessment of the MCES. Based on the review, as described above, the NRC staff concludes that the MCES will continue to maintain its ability to control and provide monitoring for releases of radioactive materials to the environment following implementation of the proposed EPU. The NRC also concludes that the MCES will continue to meet the requirements of final GDCs 60 and 64. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the MCES.

2.5.2.3 Turbine Gland Sealing System

Regulatory Evaluation

The turbine gland sealing system is provided to control the release of radioactive material from steam in the turbine to the environment. The NRC staff reviewed changes to the turbine gland sealing system with respect to factors that may affect gaseous radioactive material handling (e.g., source of sealing steam, system interfaces, and potential leakage paths). The NRC's acceptance criteria for the turbine gland sealing system are based on: (1) final GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents; and (2) final 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 anticipated operational occurrences and postulated accidents. Specific review criteria are contained in SRP Section 10.4.3.

Technical Evaluation

As discussed in PUSAR Section 2.5.2.3, the licensee will upgrade the existing main turbine to account for the increased steam flow at EPU operating conditions. The licensee evaluated the current turbine gland sealing system and determined that straight tooth packing will potentially need to be replaced with a slant tooth packing design. This type of modification would lower packing flow and increase efficiency. The licensee will confirm the potential modification during the detailed turbine design for EPU implementation. No other hardware changes are required to support operation at EPU conditions. The NRC staff finds that the licensee's design control process provides reasonable assurance that the turbine gland sealing system will continue to meet GDCs 60 and 64.

Conclusion

The NRC staff has reviewed the licensee's assessment of required changes to the turbine gland sealing system and concludes that the licensee has adequately evaluated these changes. The NRC staff concludes that the turbine gland sealing system will continue to maintain its ability to control and provide monitoring for releases of radioactive materials to the environment consistent with final GDCs 60 and 64. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the turbine gland sealing system.

2.5.2.4 Main Steam Isolation Valve Leakage Control System

This review section is not applicable since PBAPS does not have a main steam isolation valve leakage control system.

2.5.3 Component Cooling and Decay Heat Removal

2.5.3.1 Spent 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 spent fuel pool cooling and cleanup system is to cool the spent fuel assemblies and keep the spent fuel assemblies covered with water during all storage conditions. The NRC staff's review for the proposed EPU focused on the effects of the proposed EPU on the capability of the system to provide adequate cooling to the spent fuel during all operating and accident conditions. The NRC's acceptance criteria for the spent fuel pool cooling and cleanup system are based on: (1) draft GDC-4, insofar as reactor facilities shall not share systems or components unless it is shown that safety is not impaired by the sharing; (2) draft GDC-67, insofar that reliable decay heat removal systems are necessary to prevent damage to stored spent fuel; and (3) final GDC-61, insofar as it requires that fuel storage systems be designed with RHR capability reflecting the importance to safety of decay heat removal, and measures to prevent a significant loss of fuel storage coolant inventory under accident conditions. Specific review criteria are contained in SRP Section 9.1.3, as supplemented by the guidance provided in Attachment 1 to Matrix 5 of Section 2.1 of RS-001.

Technical Evaluation

Fuel Pool Cooling (Normal and Full Core Offload)

As discussed in PUSAR Section 2.5.3.1, the spent fuel cooling section of the fuel pool cooling and cleanup system (FPCCS) consists of three trains of pumps and heat exchangers. The service water (SW) system provides cooling water to the FPCCS heat exchangers. The residual heat removal (RHR) system, which the high-pressure service water (HPSW) system cools, can supply additional SFP cooling.

The increase in decay heat resulting from the EPU will increase the heat load on the FPCCS during and after refueling. However, operation at the uprated power does not affect the alignments, availability, or safety-related designations of these systems. The licensee maintains the SFP temperature within design limits for the normal and full-core offloads through existing administrative and procedural limitations that require cycle-specific core offload evaluations prior to initiating the core offload. The EPU does not change the trains of cooling used to evaluate the effects of core offload.

The licensee calculated the decay heat for the EPU using the formulation and uncertainty factors from American National Standards Institute/American Nuclear Society (ANSI/ANS) Standard 5.1 - 1979, "American National Standard for Decay Heat Power in Light Water Reactors," with two-sigma uncertainty and correction for miscellaneous actinides and activation products. The use of ANSI/ANS-5.1-1979 is a change from the PBAPS previous use of the methodology in NRC Branch Technical Position (BTP) ASB 9-2, "Residual Decay Energy for Light-Water Reactors for Long-Term Cooling." BTP ASB 9-2 is part of SRP Section 9.2.5, "Ultimate Heat Sink," Revision 2 (Reference 56). However, Revision 3 of SRP 9.2.5 (Reference 57) no longer includes the BTP and now states that ANSI/ANS-5.1 describes methods acceptable to the NRC staff for calculating residual decay heat energy.

The licensee evaluated the effect of the heat load on the SFP temperature with normal offloads added to a bounding SFP heat load from previously offloaded batches. The evaluation of the normal offload credits the SW system for directly removing the decay heat from the FPCCS heat exchangers. The basis for the heat removal capability of the FPCCS heat exchanger is a SW temperature of 90 °F.

The result of evaluation shows that, using the FPCCS alone, the licensee can maintain the SFP temperature below 140 °F with all 3 trains in service. With a single failure, the FPCCS would maintain the SFP temperature below 150 °F. In addition, the licensee evaluated a full-core offload using the RHR system. The RHR system in fuel pool cooling assist mode, assuming a HPSW temperature of 92 °F, can maintain the SFP temperature below 140 °F for a full-core offload.

The worst-case makeup requirement occurs when all cooling is lost after a full-core offload. Should this condition occur, within 1 hour the licensee can align either refueling water, demineralized water, or condensate by valve and pump manipulations to provide sufficient makeup to maintain SFP level. The heating rate is sufficiently slow to allow operator actions to initiate makeup prior to the SFP reaching boiling.

Crud Activity and Corrosion Products

As discussed in PUSAR Section 2.5.3.1.2, crud activity and corrosion products associated with spent fuel may increase slightly during operation at the uprated power. The amount of crud activity and pool quality are operational considerations and are unrelated to safety. The licensee concluded that operation at the uprated power will not adversely affect the capability of the FPCCS to maintain water clarity.

Radiation Levels

As discussed in PUSAR Section 2.5.3.1.3, the normal radiation levels around the SFP may increase slightly, primarily during fuel handling operations. Radiation levels in areas of the plant directly affected by the reactor core and spent fuel, increase by the percentage increase in the average power density of the fuel bundles. Therefore, for an EPU increase of 15%, the radiation dose rates increase by 15%.

The design of the SFP is conservative from the perspective of radiation exposure such that changes in the fuel inventory/bundle surface dose rate of 15% results in minimal changes in operating dose. The current PBAPS radiation procedures and radiation-monitoring program would detect any changes in radiation levels and initiate appropriate actions.

Summary

Based on the above, the NRC staff finds the proposed EPU acceptable with respect to the SFP cooling and cleanup system.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the SFP cooling and cleanup system and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the SFP cooling function of the system. Based on this review, the NRC staff concludes that the SFP cooling and cleanup system will continue to provide sufficient cooling capability to cool the SFP following implementation of the proposed EPU and will continue to meet the requirements of final GDC-61 and draft GDCs 4 and 67. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the SFP cooling and cleanup system.

2.5.3.2 Station Service Water Systems

Regulatory Evaluation

The station service water system (SWS) provides essential cooling to safety-related equipment and may also provide cooling to non-safety-related auxiliary components that are used for normal plant operation. The SWS includes the emergency service water (ESW) and HPSW systems. The NRC staff's review covered the characteristics of the station SWS (i.e., ESW and HPSW systems) components with respect to their functional performance as affected by adverse operational (i.e., water hammer) conditions, abnormal operational conditions, and accident conditions (e.g., a LOCA with the LOOP). The NRC staff's review focused on the additional heat load that would result from the proposed EPU. The NRC's acceptance criteria are based on: (1) draft GDC-40 and 42, insofar as they require that protection be provided for ESFs against the dynamic effects that might result from plant equipment failures, as well as the effects of a LOCA; (2) draft GDC-41, insofar that the SWS is relied upon by engineered safety features for performing their safety functions; and (3) draft GDC-52, insofar that the SWS is relied upon by containment heat removal systems for performing their safety functions; and (4) draft GDC-4, insofar as reactor facilities shall not share systems or components unless it is shown safety is not impaired by the sharing. Specific review criteria are contained in SRP Section 9.2.1, as supplemented by GL 89-13 and GL 96-06.

Technical Evaluation

Background

As discussed in PUSAR Section 2.5.3.2, the non-safety related SWS provides screened and chlorinated, once-through cooling water to various non-safety related plant systems and components during normal plant operation and shutdown periods. The SWS also supplies cooling water to the core standby cooling equipment and space coolers during normal plant operation and during shutdown periods when offsite power is available. The SWS includes pumps, valves, piping and instrumentation that provide cooling and makeup water to various non-safety related systems and components, including the turbine building closed cooling water

(TBCCW) heat exchangers and reactor building closed cooling water (RBCCW) heat exchangers.

The ESW system includes pumps, valves, piping, and instrumentation to provide cooling water from the emergency cooling tower or the Conowingo Pond to various safety-related plant systems and components. The ESW is safety-related and can operate during design flood conditions, during a loss of the Conowingo Pond, and during LOOP conditions. The ESW system picks up safety-related cooling loads, normally handled by the SW, in the event of a LOOP and/or accident conditions. In order to transfer loads from the non-safety related SW system, the ESW has safety-related isolation valves to isolate the non-safety related portion of the system.

The HPSW system pumps and associated piping and valves are safety-related and provide cooling water to the RHR heat exchangers during normal shutdown, flood conditions, and other post-accident conditions (e.g., LOOP, LOCA).

Water System Performance (Safety-Related)

Operation at the uprated power results in a greater decay heat rate, which increases the safety-related water systems cooling requirement during accident conditions. The performance of the ESW during and immediately following the most limiting design basis event, the LOCA, [[ ]] The HPSW (non-DBA emergency shutdown) heat loads will increase slightly at the uprated power. For normal shutdown, the maximum HPSW heat loads will not increase, because the initiating pressure and temperature are not changing for EPU.

The design of the safety-related portions of the HPSW and ESW systems provide a reliable supply of cooling water during and following a DBA, design-basis flood or LOOP conditions, for the following essential equipment and systems:

Services that have increased heat loads with EPU:

- RHR System Heat Exchangers

Services for which heat loads are not dependent on RTP:

- EDG Heat Exchangers (Jacket Water, Air, and Lube Oil Coolers)
- RHR Pumps Room Coolers
- RCIC Pump Room Coolers
- HPCI Pump Room Coolers
- CS Pump Room Coolers
- CS Pump Motor Oil Coolers

The licensee's evaluation concluded that the ESW and HPSW systems are adequate for operation under EPU conditions.

Water System Performance (Normal Operation)

EPU results in an increased heat load during normal operation. The increased non-safety related SWS heat loads at PBAPS are due primarily to the increased SFP cooling decay heat load, generator hydrogen and stator coolers, Alterrex air coolers, reactor feed pump oil coolers, certain turbine building area coolers, and the TBCCW and RBCCW heat exchangers. The licensee is implementing plant modifications to rerate the main generator to accommodate operation at the uprated power. The generator rotor modifications will ensure that the SW flow demands for generator stator and hydrogen cooling will be satisfied.

Suppression Pool Cooling (RHR Service Operation)

EPU results in a greater decay heat rate. The containment cooling analysis, discussed in PUSAR Section 2.6.5, shows that the post-LOCA RHR heat load increases due in part to an increase in reactor decay heat. The licensee calculated the post-LOCA containment and suppression pool responses based on an energy balance between the post-LOCA heat loads and the heat removal capacity of the RHR and HPSW. Currently, the PBAPS emergency core cooling system (ECCS) pumps require containment accident pressure (CAP) credit to provide adequate net positive suction head (NPSH) margin. The increased decay heat generated at EPU power levels will increase suppression pool temperatures and further decrease NPSH margin for the ECCS pumps. Rather than proposing an increased reliance on CAP credit, the licensee has decided to make plant modifications and apply methodology changes that will increase NPSH margin for these pumps to the extent that reliance on CAP can be eliminated. The modifications include: (1) an RHR system heat exchanger cross-tie modification; (2) an HPSW system cross-tie modification; and (3) condensate storage tank modifications. The RHR system modification will enable the operator to align a second RHR heat exchanger for post-LOCA containment heat removal. The additional cooling capacity results in a peak suppression pool temperature at uprated power operation that is lower than the current peak temperature at CLTP. The effect on HPSW is that a second HPSW pump will supply cooling water flow to the second RHR heat exchanger on the LOCA unit. There is no increase in the required design HPSW flow to any RHR heat exchanger; the combined HPSW flow rate to two RHR heat exchangers is adequate for suppression pool cooling at EPU conditions. The containment cooling analysis and equipment review demonstrate that the licensee can maintain suppression pool temperature within acceptable limits in the post-accident condition at the uprated power based on the existing capability of the HPSW system.

Summary

Based on the above, the NRC staff finds that the licensee has adequately addressed the impacts of the proposed EPU with respect to the ESW and HPSW systems.

<u>Conclusion</u>

The NRC staff has reviewed the licensee's assessment related to the effects of the proposed EPU on the ESW and HPSW systems and concludes that the licensee has adequately accounted for the increased heat loads on system performance that would result from the proposed EPU. The NRC staff concludes that the ESW and HPSW systems will continue to be protected from the dynamic effects associated with flow instabilities and provide sufficient cooling for SSCs important to safety following implementation of the proposed EPU. Therefore, the NRC staff has determined that the ESW and HPSW systems will continue to meet the requirements of draft GDCs 4, 40, 41, 42 and 52. Based on the above, the NRC staff finds the proposed EPU acceptable with respect to the ESW and HPSW systems.

2.5.3.3 Reactor Auxiliary Cooling Water Systems

Regulatory Evaluation

The NRC staff's review covered reactor auxiliary cooling water systems that are required for: (1) safe shutdown during normal operations, anticipated operational occurrences, and mitigating the consequences of accident conditions; or (2) preventing the occurrence of an accident. These systems include closed-loop auxiliary cooling water systems for reactor system components, reactor shutdown equipment, ventilation equipment, and components of the ECCS. The NRC staff's review covered the capability of the auxiliary cooling water systems to provide adequate cooling water to safety-related ECCS components and reactor auxiliary equipment for all planned operating conditions. Emphasis was placed on the cooling water systems for safety-related components (e.g., ECCS equipment, ventilation equipment, and reactor shutdown equipment). The NRC staff's review focused on the additional heat load that would result from the proposed EPU. The NRC's acceptance criteria for the reactor auxiliary cooling water system are based on: (1) draft GDC-40 and 42, insofar as they require that protection be provided for ESFs against the dynamic effects that might result from plant equipment failures, as well as the effects of a LOCA; (2) draft GDC-4, insofar as reactor facilities shall not share systems or components unless it is shown safety is not impaired by the sharing; and (3) draft GDC-41, insofar that the Reactor Auxiliary Cooling Water Systems are relied upon by engineered safety features for performing their safety functions. Specific review criteria are contained in SRP Section 9.2.2, as supplemented by GL 89-13 and GL 96-06.

Technical Evaluation

The non-safety related reactor auxiliary cooling water systems include the RBCCW system and the TBCCW system, as discussed below and as evaluated by the licensee in PUSAR Section 2.5.3.3 and in Attachment 2 to Supplement 10 to the EPU LAR (Reference 11).

Reactor Building Closed Cooling Water System

The RBCCW heat loads are mainly dependent on the reactor vessel temperature and/or flow rates in the systems cooled by the RBCCW. The flow rates in the systems cooled by the RBCCW (e.g., reactor recirculation and RWCU pumps cooling) do not change due to power uprate and therefore, are not affected by the proposed EPU. The only significant increase in heat load due to EPU is an increase in SFP cooling heat load. During normal refueling operation, the RBCCW heat load for SFP cooling is 17.5 million British thermal units per hour (MBTU/hr) at CLTP. Operation at the uprated power will increase this load to 27.0 MBTU/hr, which remains below the RBCCW system heat exchanger capacity of 51.0 MBTU/hr for two heat exchanger operation during SFP cooling. This SFP cooling heat load occurs during refueling when other RBCCW loads are offline or significantly reduced. Therefore, the increase in SFP cooling heat load does not increase RBCCW system heat loads beyond system design. The proposed EPU does not affect the operation of the remaining equipment cooled by the RBCCW (e.g., sample coolers and drain coolers) because they are not power dependent. There are negligible changes to system operating temperatures and pressures at the uprated power. There are no changes to RBCCW system operation.

The RBCCW system contains sufficient redundancy in pumps and heat exchangers to ensure that adequate heat removal capability is available during normal operation. Sufficient heat removal capacity is available to accommodate the small increase in heat load at the uprated power.

As discussed in Attachment 2 to Supplement 10 to the EPU LAR, the licensee's evaluation of the impact of EPU on the RBCCW system, the drywell ventilation system, and the reactor building ventilation system indicates that an overpressure in the cooling water lines will prevent water hammer under DBA conditions.

Turbine Building Closed Cooling Water System

The supply temperature of the TBCCW system is dependent on the heat rejected to the TBCCW system via components cooled by the system, as removed by the TBCCW heat exchangers. Operation at the uprated power will increase power-dependent heat loads on the TBCCW system, such as those related to the condensate pumps and iso-phase bus duct coolers. The TBCCW heat exchanger is capable of removing system heat loads at the uprated power, with margin. Based on the proposed modifications to the iso-phase bus ducts for EPU, the margin in the system heat exchangers for single heat exchanger operation can accommodate the increase in heat load on the TBCCW. As such, the TBCCW system will meet the requirements of the system with respect to heat loads due to EPU. There are no changes to TBCCW system flow rates as a result of iso-phase bus duct cooler modifications.

Summary

Based on the above, the NRC staff finds that the licensee has adequately addressed the impacts of the proposed EPU with respect to the RBCCW and TBCCW systems.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the reactor auxiliary cooling water systems and concludes that the licensee has adequately accounted for the increased heat loads from the proposed EPU on system performance. The NRC staff concludes that the reactor auxiliary cooling water systems will continue to be protected from the dynamic effects associated with flow instabilities and provide sufficient cooling for SSCs important to safety following implementation of the proposed EPU. Therefore, the NRC staff has determined that the reactor auxiliary cooling water systems will continue to meet the requirements of draft GDCs 4, 40, 41, and 42. Based on the above, the NRC staff finds the proposed EPU acceptable with respect to the reactor auxiliary cooling water systems.

2.5.3.4 Ultimate Heat Sink

Regulatory Evaluation

The ultimate heat sink (UHS) is the source of cooling water provided to dissipate reactor decay heat and essential cooling system heat loads after a normal reactor shutdown or a shutdown following an accident. The NRC staff's review focused on the impact that the proposed EPU has on the decay heat removal capability of the UHS. Additionally, the NRC staff's review included evaluation of the design-basis UHS temperature limit determination to confirm that post-licensing data trends (e.g., air and water temperatures, humidity, wind speed, water volume) do not establish more severe conditions than previously assumed. The NRC's acceptance criteria for the UHS are based on: (1) draft GDC-4, insofar as reactor facilities shall not share systems or components unless it is shown safety is not impaired by the sharing; (2) draft GDC-41, insofar that the UHS is relied upon by engineered safety features for performing their safety functions; and (3) draft GDC-52, insofar that the UHS is relied upon by containment heat removal systems for performing their safety functions. Specific review criteria are contained in SRP Section 9.2.5.

Technical Evaluation

As discussed in SE Section 1.2, the normal heat sink for PBAPS is the Conowingo Pond. The Conowingo Pond is a reservoir on the Susquehanna River formed by the Conowingo Dam (located approximately 8.5 miles downstream of the PBAPS site) and the Holtwood Dam (located approximately 6 miles upstream of the PBAPS site). The normal heat sink supplies cooling water to the non-safety-related circulating water system and the non-safety-related service water system. The normal heat sink also supplies the cooling water for the safety-related HPSW system and the safety-related ESW system. As discussed in PUSAR Section 2.5.3.4, the normal heat sink (i.e., Conowingo Pond) is considered the UHS at PBAPS. The maximum allowable supply temperature from the normal heat sink (92 °F) is governed by the limits in TS 3.7.2. As discussed in PUSAR Section 2.5.3.4, the proposed EPU will have no impact on the normal heat sink temperature limits or design function. The licensee also concluded that the EPU will have no impact on the normal heat sink as a source of cooling water for ESW systems that dissipate reactor decay heat and essential cooling loads after a normal reactor shutdown or shutdown following an accident.

As discussed in SE Section 1.2, the PBAPS design also includes an emergency heat sink, which provides heat removal capability for safe reactor shutdown in the event the normal heat sink (Conowingo Pond) is unavailable due to flooding or loss of the Conowingo Dam. The emergency heat sink consists of three mechanical-draft cooling towers (emergency cooling towers) with an integral water storage reservoir.

As discussed in PUSAR Section 2.5.3.4, the three emergency cooling towers are each capable of handling the heat transfer duty of one RHR heat exchanger (one HPSW pump) plus the plant auxiliary cooling requirement (one ESW pump). The licensee does not use the emergency cooling towers during normal plant operation. The design of the emergency heat sink for PBAPS allows for a maximum supply water temperature of 90 °F. The emergency cooling tower reservoir maintains a reserve water supply for 7 days post-accident operation without replenishment.

Operation at the uprated power results in increased heat load during normal operation and in a greater decay heat rate, which increases the safety-related water systems cooling requirements during accident conditions. During operation at the uprated power, the normal and emergency heat sinks must accommodate the major RHR heat exchanger heat load increase, along with other smaller increases, as discussed in SE Section 2.5.3.2. The licensee will operate the normal and emergency heat sinks so that none of the present limits (e.g., normal heat sink temperature and minimum cooling tower reservoir water level) change because of the EPU.

The licensee evaluated the emergency cooling towers for their capability to handle the increased EPU heat load for a 7-day period. The evaluation demonstrates that the towers can maintain the temperature of the water supplied within the maximum design basis temperature of 90 °F during all modes of required operation, and can maintain sufficient water inventory for a 7-day period without makeup.

Based on the above, the NRC staff finds that the licensee has adequately addressed the impacts of the proposed EPU with respect to the UHS.

Conclusion

The NRC staff has reviewed the information that was provided by the licensee for addressing the effects that the proposed EPU would have on the UHS safety function, including the licensee's validation of the design-basis UHS temperature limit based on post-licensing data. Based on the information that was provided, the NRC staff concludes that the proposed EPU will not compromise the design-basis safety function of the UHS, and that the UHS will continue to satisfy the requirements of draft GDCs 4, 41, and 52 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the UHS.

2.5.4 Balance-of-Plant Systems

2.5.4.1 Main Steam

Regulatory Evaluation

The main steam supply system (MSSS) transports steam from the NSSS to the power conversion system and various safety-related and non-safety-related auxiliaries. The NRC staff's review focused on the effects of the proposed EPU on the system's capability to transport steam to the power conversion system, provide heat sink capacity, supply steam to drive safety system pumps, and withstand adverse dynamic loads (e.g., water steam hammer resulting from rapid valve closure and relief valve fluid discharge loads). The NRC's acceptance criteria for the MSSS are based on: (1) draft GDC-40 insofar as it requires that protection be provided for ESFs against the dynamic effects that might result from plant equipment failures; and (2) draft GDC-4, insofar as reactor facilities shall not share systems or components unless it is shown safety is not impaired by the sharing. Specific review criteria are contained in SRP Section 10.3.

Technical Evaluation

Structural Evaluation of Main Steam Piping

As discussed in PUSAR Section 2.5.4.1.1, Section 3.4.1 of the CLTR addresses the effect of CPPU on flow-induced vibration (FIV) in the main steam lines (MSLs). The CLTR states that because the EPU does not affect main steam (MS) piping pressures and temperatures, there is no effect on the analyses for these parameters. In addition, the EPU does not affect seismic inertia loads, seismic building displacement load, or safety relief valve (SRV) discharge loads, thus, there is no effect on the analyses for these load cases.

The licensee stated that SRV setpoint tolerance is independent of an EPU and that the PBAPS transient analyses conservatively bound the existing SRV setpoint tolerance analytical limits. The licensee monitors in-service surveillance of SRV setpoint performance test results separately for compliance to the TSs and inservice testing program. The in-service surveillance testing of PBAPS SRVs has not shown an indication for high setpoint drift greater than 3%.

Increased MSL flow may affect vibration of the piping during normal operation. The vibration frequency, extent, and magnitude depend upon plant-specific parameters, valve locations, the valve design, and piping support arrangements. The licensee will assess the effects of the EPU on FIV of the piping by vibration testing during initial plant operation at the higher steam flow rates. Because FIV may increase incidents of SRV leakage, PBAPS has procedures and installed instrumentation in place to detect and take actions concerning SRV seat leakage. These procedures and installed instrumentation are capable of monitoring for SRV seat leakage at EPU rated steam flow conditions. The licensee performed analyses and will perform testing to investigate and address the potential for acoustic resonance from the increased steam flow past the SRV standpipes and other such branch connections.

Main Steam Line Flow Restrictors

As discussed in PUSAR Section 2.5.4.1.2, Section 3.7 of the CLTR addresses the effect of CPPU on the MSL flow restrictors. The CLTR states that, during operation at the uprated power, the flow restrictors need to pass a higher flow rate. The increase in steam flow rate should have no significant effect on flow restrictor erosion. However, the increase in steam flow rate will result in an increased pressure drop. There is no effect on the structural integrity of the MSL flow element (restrictor) due to the increased differential pressure because the choke flow condition bounds the restrictor's design and analysis.

After a postulated steam line break outside containment, the fluid flow in the broken steam line increases until the MSL flow restrictor limits the break flow. [[

]] The licensee originally analyzed the PBAPS restrictors for these flow conditions and therefore the restrictors remain within the acceptable calculated differential pressure drop and choke flow limits under EPU conditions.

Summary

The NRC staff concludes that the licensee has adequately addressed the impact of the EPU on the MSSS.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the MSSS and concludes that the licensee has adequately accounted for the effects of changes in plant conditions on the design of the MSSS. The NRC staff concludes that the MSSS will maintain its ability to transport steam to the power conversion system, provide heat sink capacity, supply steam to steam-driven safety pumps, and withstand steam hammer. The NRC staff further concludes that the MSSS will continue to meet the requirements of draft GDCs 4 and 40. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the MSSS.

2.5.4.2 Main Condenser

Regulatory Evaluation

The main condenser (MC) system is designed to condense and deaerate the exhaust steam from the main turbine and provide a heat sink for the turbine bypass system (TBS). For BWRs without a main steam isolation valve (MSIV) leakage control system, the MC system may also serve an accident mitigation function to act as a holdup volume for the plate out of fission products leaking through the MSIVs following core damage. The NRC staff's review focused on the effects of the proposed EPU on the steam bypass capability with respect to load rejection assumptions, and on the ability of the MC system to withstand the blowdown effects of steam from the TBS. The NRC's acceptance criteria for the MC system are based on final 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 10.4.1.

Technical Evaluation

The licensee's evaluation related to the MC was provided in PUSAR Section 2.5.3.4. As stated in the CLTR, the increase in steam flow increases the heat removal requirement for the condenser. The additional power level increases the non-condensable gases generated by the reactor. The MC rejects heat to the circulating water system and thereby maintains adequately low condenser pressure, as recommended by the turbine vendor. Maintaining adequately low condenser pressure assures the efficient operation of the turbine-generator and minimizes wear on the turbine last stage blades.

Operation at the uprated power increases the heat rejected to the condenser and, therefore, reduces the difference between the operating backpressure and the recommended maximum condenser backpressure. If condenser backpressures approach the main turbine backpressure limitation, then reactor thermal power reduction would be required to reduce the heat rejected to the condenser and maintain condenser pressure within the turbine requirements.

The licensee evaluated the performance of the condenser for EPU operation. The licensee based the evaluation on a design duty over the actual range of circulating water inlet temperatures. The evaluation shows that the condenser backpressure remains below the high alarm setpoint, the scram setpoint, and the turbine trip setpoint during normal operation. As a result, the licensee will not modify the MC for EPU operation. Condenser hotwell temperature limitations may require load reductions due to circulating water inlet temperatures; however, the licensee anticipates this to be an infrequent occurrence.

EPU operation decreases the margin for the MC storage capacity from approximately 3.1 minutes at CLTP to 2.7 minutes at EPU operation. As the 2-minute holdup time for the decay of short-lived radioactive isotopes remains a conservative decay time, this remains acceptable for EPU operation.

The EPU does not increase the absolute value in pounds mass per hour of the steam bypassed to the MC during a load rejection event. The condenser backpressure during a steam dump scenario remains below the high backpressure scram setpoint. In addition, the holdup time for the plate-out of fission products leaking through the MSIVs following core damage remains conservative.

Based on the above, the NRC staff finds that the licensee has adequately addressed the impacts of the proposed EPU with respect to the MC system.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the MC system and concludes that the licensee has adequately accounted for the effects of changes in plant conditions on the design of the MC system. The NRC staff concludes that the MC system will continue to maintain its ability to withstand the blowdown effects of the steam from the TBS and thereby continue to meet final GDC-60 with respect to controlling releases of radioactive effluents. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the MC system.

2.5.4.3 Turbine Bypass

Regulatory Evaluation

The TBS is designed to discharge a stated percentage of rated main steam flow directly to the MC system, bypassing the turbine. This steam bypass enables the plant to take step-load reductions up to the TBS capacity without the reactor or turbine tripping. The system is also used during startup and shutdown to control reactor pressure. For a BWR without an MSIV leakage control system, the TBS could also provide an accident mitigation function. A TBS, along with the MSSS and MC system, may be credited for mitigating the effects of MSIV leakage during a LOCA by the holdup and plate out of fission products. The NRC staff's review for the TBS focused on the effects that the proposed EPU have on load rejection capability, analysis of postulated system piping failures, and the consequences of inadvertent TBS operation. The NRC's acceptance criteria for the TBS are based on draft GDCs 40 and 42, insofar as they require that protection be provided for ESFs against the dynamic effects that might result from plant equipment failures, as well as the effects of a LOCA. Specific review criteria are contained in SRP Section 10.4.4.

Technical Evaluation

As discussed in PUSAR Section 2.5.4.3, the TBS provides a means of accommodating excess steam generated during normal plant maneuvers and transients. As stated in the CLTR, the increase in steam flow during operation at the uprated power reduces the relative capacity of the TBS.

The licensee used the credited bypass capacity of 2.82 million pounds mass per hour (Mlbm/hr) (unchanged from CLTP) as an input to the reload analysis process for the evaluation of anticipated operational occurrence (AOO) events that credit the TBS. Each of the 9 bypass valves pass a steam flow of 0.402 Mlbm/hr, resulting in a system bypass capacity of approximately 3.62 Mlbm/hr. Operation at the uprated power does not change the bypass capacity in terms of mass flow. At the EPU conditions, rated steam flow is 16.171 Mlbm/hr. As such, the system bypass capability, in terms of rated steam flow, is approximately 22.39% (i.e., 3.62/16.171). Therefore, the bypass capacity at PBAPS remains adequate for normal operational flexibility at EPU rated thermal power.

Based on the above, the NRC staff finds that the licensee has adequately addressed the impacts of the proposed EPU with respect to the TBS.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the TBS. The NRC staff concludes that the licensee has adequately accounted for the effects of changes in plant conditions on the design of the TBS. The NRC staff concludes that the TBS will continue to mitigate the effects of MSIV leakage during a LOCA and provide a means for shutting down the plant during normal operations. The NRC staff further concludes that TBS failures will not adversely affect essential SSCs. Based on this, the NRC staff concludes that the TBS will continue to meet draft GDCs 40 and 42. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the TBS.

2.5.4.4 Condensate and Feedwater

Regulatory Evaluation

The condensate and feedwater system (CFS) provides feedwater at a particular temperature, pressure, and flow rate to the reactor. The only part of the CFS classified as safety-related is the feedwater piping from the NSSS up to and including the outermost containment isolation valve. The NRC staff's review focused on how the proposed EPU affects previous analyses and considerations with respect to the capability of the CFS to supply adequate feedwater during plant operation and shutdown, and isolate components, subsystems, and piping in order to preserve the system's safety function. The NRC's acceptance criteria for the CFS are based on: (1) draft GDCs 40 and 42, insofar as they require that protection be provided for ESFs against the dynamic effects that might result from plant equipment failures, as well as the effects of a LOCA; and (2) draft GDC-4, insofar as reactor facilities shall not share systems or components unless it is shown safety is not impaired by the sharing. Specific review criteria are contained in SRP Section 10.4.7.

Technical Evaluation

As discussed in PUSAR Section 2.5.4.4, the CFS provides a reliable supply of FW at the temperature, pressure, quality, and flow rate as required by the reactor. The PBAPS CFS is required for normal plant operation and is not safety-related. However, the performance of the CFS has a major effect on plant availability and capability to operate at EPU conditions. For operation at the uprated power, the increase in power level increases the FW requirements of the reactor. [[

]] Non-safety related modifications are needed to the CFS to support normal operation during EPU conditions. The licensee proposes to make the following changes to non-safety related components in the CFS to meet the EPU performance requirements:

- Reactor Feedpump Turbines - Repair degraded conditions
- FW Heater 3A2 - Heater replacement
- FW Heater 3B2 - Heater replacement
- FW Heater 3C3 - Heater replacement
- Condensate Filter/Demineralizer Vessels - Two additional vessels

Though the following components do not require changes for operation at EPU, the licensee expects their upgrade to improve EPU operating margins:

- Condensate Pumps – Upgrade to increase pumping capacity

Normal Operation

System operating flows at EPU increase to approximately 113.3% of rated flow at the CLTP. The CFS modifications assure acceptable performance with the new system operating conditions, provided that three condensate and three reactor FW pumps are in operation. The licensee evaluated the FW heater design to verify that the heaters are acceptable for the higher FW heater flows, temperatures, and pressures for operation at the uprated power. The licensee determined that FW heaters 3A2, 3B2, and 3C3 have existing material condition issues that increased flows at EPU conditions may exacerbate. Therefore, the licensee plans to replace these heaters prior to EPU operation.

Transient Operation

The licensee evaluated the FW system to account for FW demand transients. The evaluation showed the FW system could support a flow transient of at least 105% of EPU steady-state operating flows with adequate margins. For system operation with all system pumps available, the predicted operating parameters are within the component capabilities.

The licensee evaluated the post-condensate and FW pump trip system capacity. The evaluation showed that following a condensate or FW pump trip, insufficient capacity is available to support the normal, steady-state EPU flows. As a result, a condensate or reactor FW pump trip requires a reduction in the plant power level. PBAPS currently employs reactor recirculation runback logic to respond to condensate and FW pump trips and operation at the uprated power does not require modification to the reactor recirculation runback logic in response to a condensate or FW pump trip.

Condensate Demineralizers

The licensee evaluated the effect of operation at the uprated power on the condensate demineralizers. Operation at the uprated power increases flow beyond the demineralizers' capability. As a result, the licensee plans to modify the demineralizers to provide the additional capacity to support full flow operation while maintaining appropriate filter flux rates.

Summary

Based on the above, the NRC staff finds that the licensee has adequately addressed the impacts of the proposed EPU with respect to the CFS.

<u>Conclusion</u>

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the CFS and concludes that the licensee has adequately accounted for the effects of changes in plant conditions on the design of the CFS. The NRC staff concludes that the CFS will continue to maintain its ability to satisfy feedwater requirements for normal operation and shutdown, maintain isolation capability in order to preserve the system safety function, and not cause failure of safety-related SSCs. The NRC staff further concludes that the CFS will continue to meet the requirements of draft GDCs 4, 40 and 42. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the CFS.

2.5.5 Waste Management Systems

2.5.5.1 Gaseous Waste Management System

<u>Regulatory Evaluation</u>

The gaseous waste management system (GWMS) involves the gaseous radwaste system, which deals with the management of radioactive gases collected in the offgas system or the waste gas storage and decay tanks. In addition, it involves the management of the condenser air removal system; the gland seal exhaust and the mechanical vacuum pump operation exhaust; and the building ventilation system exhausts. The NRC staff's review focused on the effects that the proposed EPU may have on: (1) the design criteria of the GWMS; (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 NRC's acceptance criteria for the GWMS 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) final 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) final GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents; (4) final 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. Specific review criteria are contained in SRP Section 11.3.

Technical Evaluation

The GWMS collects, controls, processes, stores, and disposes of gaseous wastes generated during normal operation. The design of the system allows for the processing and controlling of the release of gaseous radiological effluents to the environment such that the total radiation exposure of persons in offsite areas is ALARA. The licensee administratively controls the release rate to remain within limits and is principally a function of fuel cladding performance, main condenser air inleakage, and charcoal adsorber performance. These factors are not a function of reactor power. However, the power uprate has a secondary effect in that any fuel pin leaks will release greater quantities of fission product gasses and the higher average neutron flux will activate a greater fraction of condenser inleakage.

Radiolysis of water (i.e., formation of H_2 and O_2) in the core increases linearly with power. However, because the offgas recombiner and associated condenser remove most of the radiolysis products from the waste gas stream as liquid water, this increase has a negligible effect on other portions of the offgas system.

As discussed in PUSAR Section 2.5.5.1.1, the PBAPS site-specific CLTP design-basis radiolytic gas production rate, 0.068 cubic feet per minute per megawatt thermal (cfm/MWt). The current actual radiolytic gas production rate is 0.052 cfm/MWt for PBAPS, Unit 2, and 0.046 cfm/MWt for PBAPS, Unit 3. As these rates are proportional to reactor power, the radiolytic gas flowrate is expected to increase approximately 12% under the proposed EPU conditions. This would result in a rate of approximately 0.058 cfm/MWt for PBAPS, Unit 2, and 0.052 cfm/MWt for PBAPS, Unit 3. As such, the NRC staff concludes that there is sufficient margin such that the design basis radiolytic gas production rate will be maintained under EPU conditions.

PBAPs TS 3.7.5, "Main Condenser Offgas," control the fission gas releases to the environment consistent with the assumptions for a main condenser offgas system failure event, as discussed in the TS Bases and in UFSAR Section 9.4.5. The TS requirements are not being changed for the proposed EPU.

As discussed in PUSAR Section 2.5.5.1.1, the GWMS design criteria ensure that the system will meet the plant licensing basis for controlling gaseous waste such that the total radiation exposure of persons in offsite areas will be within the applicable guideline values of 10 CFR 20.1302 and 10 CFR Part 50, Appendix I.

As discussed in PUSAR Section 2.5.5.1.2, radiolysis of water in the core increases linearly with power, thus increasing the heat load on the offgas recombiner and related components. The licensee stated that these increases have been evaluated and it has been confirmed that sufficient margin remains in the PBAPS offgas system component design to ensure that the system will continue to satisfy the plant licensing basis.

Based on the above the NRC staff concludes that operation at the uprated power does not change the plant gaseous waste licensing basis and the GWMS design criteria (for the offgas portion). Therefore, the proposed EPU is acceptable with respect to the GWMS.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the gaseous waste management systems. The NRC staff concludes that the licensee has adequately accounted for the effects of the increase in fission product and amount of gaseous waste on the abilities of the GWMS to control releases of radioactive materials and preclude the possibility of an explosion if the potential for explosive mixtures exists. The NRC staff finds that the GWMS will continue to meet its design functions following implementation of the proposed EPU. The NRC staff further concludes that the licensee has demonstrated that the GWMS will continue to meet the requirements of 10 CFR 20.1302; final GDCs 3, 60, and 61; and 10 CFR Part 50, Appendix I, Sections II.B, II.C, and II.D. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the GWMS.

2.5.5.2 Liquid Waste Management System

Regulatory Evaluation

The NRC staff's review for liquid waste management system (LWMS) focused on the effects that the proposed EPU may have on previous analyses and considerations related to the system design, design objectives, design criteria, methods of treatment, expected releases, and principal parameters used in calculating the releases of radioactive materials in liquid effluents. The NRC's acceptance criteria for the LWMS 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) final GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents; (3) final GDC-61, insofar as it requires that systems that contain radioactivity be designed with appropriate confinement; and (4) 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 criterion. Specific review criteria are contained in SRP Section 11.2.

Technical Evaluation

Waste Volumes

As discussed in Section 2.5.5.2.1 of the PUSAR, increased power levels and steam flow result in the generation of slightly higher levels of liquid radwaste (proportional to the increase in RTP). The largest sources of liquid waste are from the backwash of condensate and RWCU filter-demineralizers. Other increases in the LWMS load, such as increased leakage due to higher system pressures, are minimal. The effect of EPU on the LWMS is primarily a result of the increased load on condensate filter/demineralizers. Similarly, because of slightly higher levels of activation and fission products, the RWCU filter-demineralizer requires backwashes that are more frequent.

Because the RWCU flow rate will remain the same as CLTP with an increase in contaminate concentration, the licensee expects the RWCU system to experience a slight increase in filter/demineralizer backwash frequency. Because the liquid volume does not increase appreciably for EPU, the current design and operation of the LWMS should accommodate the effects of EPU with no change.

Coolant Fission and Corrosion Product Levels

As discussed in Section 2.5.5.2.2 of the PUSAR, increased power levels and steam flow result in the generation of slightly higher levels of coolant concentrations of fission and corrosion products. For evaluating the radiological effects of the EPU, the licensee determined reactor coolant fission and corrosion product radioactivity levels using ANSI/ANS-18.1-1999. For the evaluation, the licensee assumed that the operational radiological sources increased by the EPU fraction, which is 20% relative to OLTP. The evaluation determined that there is adequate margin between the actual operation sources and design basis sources to accommodate the 20% increase. Therefore, the current design basis sources remain bounding.

Summary

Based on the above, the NRC staff finds that the licensee has adequately addressed the impacts of the proposed EPU with respect to the LWMS.

<u>Conclusion</u>

The NRC staff has reviewed the licensee's assessment related to the LWMS. The NRC staff concludes that the licensee has adequately accounted for the effects of the increase in fission product and amount of liquid waste on the ability of the LWMS to control releases of radioactive materials. The NRC staff finds that the LWMS will continue to meet its design functions following implementation of the proposed EPU. The NRC staff further concludes that the licensee has demonstrated that the LWMS will continue to meet the requirements of 10 CFR 20.1302, final GDCs 60 and 61, and 10 CFR Part 50, Appendix I, Sections II.A and II.D. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the LWMS.

2.5.5.3 Solid Waste Management System

<u>Regulatory Evaluation</u>

The NRC staff's review for the solid waste management system (SWMS) focused on the effects that the proposed EPU may have on previous analyses and considerations related to the design objectives in terms of expected volumes of waste to be processed and handled, the wet and dry types of waste to be processed, the activity and expected radionuclide distribution contained in the waste, equipment design capacities, and the principal parameters employed in the design of the SWMS. The NRC's acceptance criteria for the SWMS 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) final GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents; (3) final GDC-63, insofar as it requires that systems be provided in waste handling areas to detect conditions that may result in excessive radiation levels, (4) final 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 anticipated operational occurrences (AOOs), and postulated accidents; and (5) 10 CFR Part 71, which states requirements for radioactive material packaging. Specific review criteria are contained in SRP Section 11.4.

Technical Evaluation

Coolant Fission and Corrosion Product Levels

The SWMS collects, monitors, processes, and stores processed radioactive waste prior to offsite disposal. As discussed in PUSAR Section 2.5.5.3.1, increased power levels and steam flow result in the generation of slightly higher levels of coolant concentrations of fission and corrosion products. For evaluating the radiological effects of the EPU, the licensee assumed that the operational radiological sources increased by the EPU fraction, which is 20% relative to OLTP. The evaluation determined that there is adequate margin between the actual operation sources and design basis sources to accommodate the 20% increase. Therefore, the licensee's current design basis sources remain bounding. In addition, the EPU does not affect radiation effluent limits and monitoring requirements because they are independent of reactor thermal power.

The radiological sources associated with EPU have been reviewed and these changes are small such that the current design and operation of the SWMS will accommodate the effects of the EPU with no changes affecting the existing equipment and procedures that control waste shipments and releases to the environment will continue to ensure that releases remain within the applicable regulatory guidance.

Waste Volumes

As discussed in PUSAR Section 2.5.5.3.2, increased power levels and steam flow result in the generation of slightly higher levels of liquid and solid radwaste.

The waste streams for the SWMS are: (1) dry active waste; and (2) spent ion exchange resin and filter sludge. The EPU does not affect dry active waste so the volume and mix of dry active waste is unchanged. The effect of EPU on the SWMS is primarily a result of the increased load on condensate filter/demineralizers. The licensee expects the increased demineralizer loads to increase the volumes of spent ion exchange resin and filter sludge. Specifically, the increased level of condensate backwash may require: (1) expanding polyelectrolyte treatment; and (2) retrofitting a third condensate phase separator to accept polyelectrolyte treatment. The licensee's evaluation conservatively estimated that the increase in solid radwaste volume would increase proportionally to the increase in RTP.

The licensee processes wet radwaste on a batch basis. According to the PBAPS UFSAR, when the licensee has collected a sufficient volume in the waste sludge tank, the licensee pumps the contents to a condensate phase separator for further processing.

When the licensee has collected sufficient volume in a phase separator, the licensee isolates that phase separator and mixes its contents to obtain a homogeneous slurry at the required solids concentration range. The licensee then pumps the slurry to the dewatering system. The licensee may need to increase the amount of batches processed to accommodate for the increase in wet solid waste. However, because the actual solid radwaste volume at the uprated power is less than the current design basis waste volume, the licensee can accommodate the increase in wet solid waste volume without the need for increased batches.

The EPU does not generate a new type of waste or create a new waste stream. As a result, the operation at the uprated power does not change the types of radwaste that require shipment. In addition, because the solid volume does not increase above the current design basis waste volume, the current design and operation of the procedures that control waste shipments and releases to the environment should continue to ensure that releases remain within the applicable regulatory guidance.

Summary

Based on the above, the NRC staff finds that the licensee has adequately addressed the impacts of the proposed EPU with respect to the SWMS.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the SWMS. The NRC staff concludes that the licensee has adequately accounted for the effects of the increase in fission product and amount of solid waste on the ability of the SWMS to process the waste. The NRC staff finds that the SWMS will continue to meet its design functions following implementation of the proposed EPU. The NRC staff further concludes that the licensee has demonstrated that the SWMS will continue to meet the requirements of 10 CFR 20.1302, final GDCs 60, 63, and 64, and 10 CFR Part 71. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the SWMS.

2.5.6 Additional Considerations

2.5.6.1 Emergency Diesel Engine Fuel Oil Storage and Transfer System

Regulatory Evaluation

Nuclear power plants are required to have redundant onsite emergency power supplies of sufficient capacity to perform their safety functions (e.g., power diesel engine-driven generator sets), assuming a single failure. The NRC staff's review focused on increases in emergency diesel generator electrical demand and the resulting increase in the amount of fuel oil necessary for the system to perform its safety function. The NRC's acceptance criteria for the emergency diesel engine fuel oil storage and transfer system are based on: (1) draft GDC-40, insofar as it requires that protection be provided for ESFs against the dynamic effects that might result from plant equipment failures; (2) draft GDC-4, insofar as reactor facilities shall not share systems or components unless it is shown safety is not impaired by the sharing; and (3) final GDC-17, insofar as it requires onsite power supplies to have sufficient independence and redundancy to perform their safety functions, assuming a single failure. Specific review criteria are contained in SRP Section 9.5.4.

Technical Evaluation

As discussed in PUSAR Section 2.5.6.1, the licensee will operate at the uprated power by utilizing existing equipment operating at or below the nameplate rating and within the calculated brake horsepower for the required pump motors. UFSAR Section 8.5.2 defines the time periods verses loading requirements for each emergency diesel generator (EDG). During operation at the uprated power level, the licensee expects no increase in electrical equipment demand on the EDGs, with the exception of the additional HPSW pump motor and RHR heat exchanger cross-tie MOV loads. The RHR heat exchanger cross-tie modification requires the loading of an additional HPSW pump for long-term containment cooling. The additional loading due to the RHR heat exchanger cross-tie modification was evaluated by the licensee found to be acceptable.

The licensee determined that the RHR heat exchanger cross-tie modification would result in increased EDG fuel oil consumption due to the HPSW pump and MOV loads. As a result, the licensee has proposed a TS modification to increase the minimum required EDG fuel oil storage capacity from 31,000 gallons per tank to 33,000 gallons per tank. This TS change was evaluated by the NRC staff in SE Section 3.23 and was found to be acceptable. Except for the fuel oil storage tank level alarm setpoint changes associated with the TS change, operation at the uprated power does not require physical changes to the EDG fuel oil storage and transfer system.

The NRC concludes that the licensee has adequately addressed changes to the fuel oil storage and transfer system based on the EPU conditions.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the amount of required fuel oil for the emergency diesel generators and concludes that the licensee has adequately accounted for the effects of the increased electrical demand on fuel oil consumption. The NRC staff concludes that the fuel oil storage and transfer system will continue to provide an adequate amount of fuel oil to allow the diesel generators to meet the onsite power requirements of final GDC-17 and draft GDCs 4, and 40. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the fuel oil storage and transfer system.

2.5.6.2 Light Load Handling System (Related to Refueling)

Regulatory Evaluation

The light-load handling system (LLHS) includes components and equipment used in handling new fuel at the receiving station and the loading of spent fuel into shipping casks. The NRC staff's review covered the avoidance of criticality accidents, radioactivity releases resulting from damage to irradiated fuel, and unacceptable personnel radiation exposures. The NRC staff's review focused on the effects of the new fuel on system performance and related analyses. The NRC's acceptance criteria for the LLHS are based on: (1) final GDC-61, insofar as it requires that systems that contain radioactivity be designed with appropriate confinement and with suitable shielding for radiation protection; and (2) final GDC-62, insofar as it requires that criticality be prevented. Specific review criteria are contained in SRP Section 9.1.4.

Technical Evaluation

Section 6.8 of the CLTR states that the CPPU does not significantly affect systems that are not specifically addressed in the CLTR. ELTR1, Section 5.12 and Appendix J, also approved by the NRC for use as guidelines for EPUs, support CLTR Section 6.8.

The CLTR does not specifically address the LLHS. Therefore, based on Section 6.8 of the CLTR, the proposed EPU does not significantly affect the LLHS. Accordingly, the NRC staff concludes that the LLHS, as currently designed and described in PBAPS UFSAR Sections 10.2, "New Fuel Storage," 10.3, "Spent Fuel Storage," and 10.4, "Tools and Servicing Equipment," should continue to meet the requirements of the current licensing basis for radioactivity releases and prevention of criticality accidents. Therefore, the NRC staff finds that the proposed EPU is acceptable with respect to the LLHS.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the new fuel on the ability of the LLHS to avoid criticality accidents and concludes that the licensee has adequately incorporated the effects of the new fuel in the analyses. Based on this review, the NRC staff further concludes that the LLHS will continue to meet the requirements of final GDCs 61 and 62 for radioactivity releases and prevention of criticality accidents. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the LLHS.

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 (Mark II containments only); (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) draft GDC-40 and 42, insofar as they require that protection be provided for ESFs against the dynamic effects that might result from plant equipment failures, as well as the effects of a LOCA; (2) draft GDC-10, insofar as it requires that reactor containment be designed to sustain the initial effects of gross equipment failures, such as a large coolant boundary break, without loss of required integrity and, together with other engineered safety features as may be necessary, to retain functional capability for as long as the situation requires; (3) draft GDC-49, 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, the pressures and temperatures resulting from the largest credible energy release following a LOCA, including considerable margin for effects from metal-water or other chemical reactions that could occur as a consequence of failure of emergency core cooling systems; (4) draft GDC-12, insofar as it requires that instrumentation and controls be provided as required to monitor and maintain variables within prescribed operating ranges; and (5) final 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.

Technical Evaluation

PBAPS, Units 2 and 3, are boiling-water reactor (BWR) plants of the BWR/4 design with Mark I type pressure suppression containments. As described in Section 5.1.2 of the UFSAR, the primary containment encloses the reactor vessel, the reactor coolant recirculation system, and other branch connections of the RCS. The major elements of the primary containment are the drywell, the pressure suppression chamber (or wetwell) that stores a large volume of water (suppression pool), the connecting vent pipe system between the drywell and the wetwell, isolation valves, vacuum breakers, containment cooling systems and other service equipment.

The drywell is a steel pressure vessel with a spherical lower portion and a cylindrical upper portion. The wetwell is a toroidal shape steel pressure vessel located below and encircling the drywell. The drywell-to-wetwell vents are connected to a vent header contained within the airspace of the wetwell. Downcomer pipes project downwards from the vent header and terminate below the water surface of the suppression pool so that in the event of any pipe failure in the drywell, the released steam would pass directly to the water where it would be condensed. The vacuum breakers equalize the pressure between the wetwell and the drywell to prevent a backflow of water from the suppression pool into the vent system.

The results of design-basis accident (DBA) safety analysis depend on the initial power level at the onset of the accident, and therefore, the proposal to operate at the EPU conditions requires DBA re-analysis at the EPU power level. The containment design basis is primarily established based on the LOCA and the actuation of the SRVs and their discharge into the suppression pool. During the EPU operation, the reactor vessel steam dome pressure remains the same as at its pre-EPU value, and therefore, the EPU is regarded as a constant pressure power uprate.

The PBAPS UFSAR documents the current results of short-term and long-term containment analyses. The short-term analysis is directed primarily at determining the drywell pressure and gas temperature response during the initial blowdown of the reactor vessel inventory to the containment following a DBA LOCA. 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 the proposed EPU on the events yielding the limiting containment pressure and temperature responses are described below.

The licensee performed the EPU containment analysis in accordance with the guidelines in General Electric (GE) Licensing Topical Report (LTR) NEDC-32424P-A (Reference 21) using GE computer codes LAMB (Reference 87), M3CPT (Reference 88) and Super Hex (SHEX) (Reference 89). The use of LAMB and M3CPT codes is approved by the NRC for short term containment LOCA analysis (References 21 and 87). Regarding the use of SHEX for the LOCA and abnormal events long-term containment analysis, Section 4.1 of the NRC SE for the CLTR (Reference 20) states, in part:

> The NRC has performed independent confirmatory analyses on extended uprates for both Mark I and Mark III containment designs and found the results consistent with SHEX results. Therefore, the confirmatory calculations with SHEX (benchmarking with current licensing basis assumptions - pre-uprate) for plant specific modeling are not required for extended power uprates for Mark I and Mark III containment designs. . .

Short-Term LOCA Analysis for Drywell Pressure Response

The short-term analysis for drywell pressure response covers the blowdown period during which the maximum drywell pressure and differential pressure between drywell and wetwell occur. The short-term design-basis LOCA (DBLOCA) analysis, which assumes a large double-ended guillotine break of a recirculation suction line, hereinafter called as recirculation suction line break (RSLB), resulted in the maximum drywell pressure. This analysis used NRC-approved analytic methods for EPUs. The licensee used the M3CPT computer code for the short term containment pressure and temperature response. Refer to Section 2.6.3 of this SE for the mass and energy (M&E) release analysis computer codes.

In response to an NRC staff RAI, the licensee, in Supplement 7 to the EPU LAR (Reference 8), provided a comparison of the input values between the current and the EPU analysis. The values of the following input parameters remain unchanged: (a) [[ ]] as the RSLB critical flow model; (b) break flow area; (c) reactor decay heat model according to ANS 5-1971 plus 20%; (d) reactor thermal power at 2% above rated thermal power (RTP) to include instrument uncertainty effects; (e) Initial containment pressure; (f) Initial wetwell gas and suppression pool temperature; (g) Initial drywell and wetwell relative humidities; (h) suppression pool level at its maximum TS limit; (i) Initial downcomer submergence height; (j) drywell-to-wetwell vent system pressure loss coefficient; (k) [[ ]]; (l) time from scram at which main steam isolation valves (MSIVs) start to close; (m) MSIV closure time; (n) time from scram at which feedwater (FW) isolation valve start to close; (o) FW valve closure time; (p) drywell, wetwell gas space, and suppression pool volumes; and (q) Initial suppression pool height.

In an RAI, the NRC staff requested the licensee to explain the basis for the assumed vent system pressure loss coefficient used in the analysis that maximizes the peak drywell pressure during the initial blowdown period. In Supplement 7 to the EPU LAR (Reference 8), the licensee stated that the plant-specific vent system pressure loss coefficients for PBAPS were developed during the Mark I containment long-term program (Reference 97) and validated in an Electric Power Research Institute (EPRI) 1/12 scale model test (Reference 101).

In Supplement 7 to the EPU LAR, the licensee also provided input values that have changed in the EPU analysis from those in the current analysis, and provided appropriate justification for the changes where the conservatism is reduced as follows:

(a) The EPU analysis used 1068 psia as the initial reactor pressure, whereas the current analysis used 1053 psia. In Supplement 17 to the EPU LAR (Reference 18), the licensee stated that the [[ ]]

(b) The EPU analysis used 70 °F as the initial drywell gas temperature, whereas the current analysis used 145 °F. [[ ]]

(c) The EPU analysis used 384 °F as the initial FW temperature, whereas the current analysis used 387 °F. The licensee stated that [[ ]] The NRC staff finds the licensee's justification acceptable because the lower FW temperature with higher density results in a conservatively greater mass flow for a constant volume FW flow rate.

The core spray (CS) system flow and the low-pressure coolant injection (LPCI) mode flow of the residual heat removal (RHR) system are not modeled both in the EPU and current analysis because the peak drywell pressure occurs before the initiation of these flows.

The licensee provided EPU short-term peak pressure analysis results for two cases, designated as "design case" and "bounding case." For the design case, the licensee used 2.5 psig, 70 °F, and 20% as initial values of drywell pressure, drywell gas temperature and drywell relative humidity, respectively. The licensee stated that the purpose of the design case analysis was to perform a highly conservative hypothetical analysis to demonstrate that a DBLOCA initiated under EPU conditions would not challenge the containment design pressure of 56 psig. The licensee stated that the design case initial drywell temperature of 70 °F is well below the lowest initial drywell temperature that can be achieved while operating at power and was therefore conservative for demonstrating the maximum containment pressure response at EPU conditions. The design case initial drywell pressure of 2.5 psig is greater than the reactor scram setpoint limit or the maximum TS limit of 2.0 psig.

For the bounding case, the licensee used 2.0 psig, 125 °F, and 20% as initial values of drywell pressure, gas temperature and relative humidity, respectively. The initial drywell pressure of 2 psig represents the maximum normal operating drywell pressure that could occur. In Supplement 7 to the EPU LAR, the licensee stated that the initial drywell gas temperature of 125 °F has a statistical basis and represents the lower statistical bound (2-sigma uncertainty) of the 5-year historical normal drywell operating temperature during power operation of the PBAPS units. The licensee stated that the bounding case having [[

]] is a conservative prediction of containment pressure response due to a DBLOCA under the EPU conditions. [[

]] The licensee therefore used the bounding case peak pressure value as a conservative value of 'P_a' for 10 CFR Part 50, Appendix J leak rate testing. The peak containment pressure result for the bounding case analysis, 48.7 psig, is below the current "P_a" value of 49.1 psig stated in PBAPS TS 5.5.12. The licensee made a conservative decision to keep the current value of 'P_a' of 49.1 psig in the TS, which the NRC staff finds acceptable.

Table 2.6-1 of the PUSAR presents the results of the short-term LOCA containment pressure analysis at EPU and its design limit. The peak drywell pressure results for the EPU limiting case from this table are reproduced in Table 2.6.1-1 below. Based on the use of acceptable analysis methods and conservative analysis inputs and assumptions, which resulted in a peak drywell pressure less than the containment design pressure, the NRC staff finds the licensee's short-term drywell pressure response results at EPU acceptable.

Table 2.6.1-1
EPU Short-Term LOCA Containment Pressure Response Results

Parameter	At CLTP from UFSAR	EPU Analysis Bounding Case	EPU Analysis Design Case	Design Limit
Peak drywell pressure (psig)	47.8	48.7	50.4	56

Long-Term Drywell Gas Temperature Response Analysis for Environmental Qualification

The licensee used the SHEX computer code for the long-term drywell gas temperature response analysis for the environmental qualification (EQ) of equipment. The licensee stated that the most limiting drywell gas temperature occurs for a small steam line break (SSLB) accident. By analyzing several break sizes in accordance with NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment," Revision 1, dated July 1981 (ADAMS Accession No. ML031480402), the licensee determined that the break area of 0.25 ft^2 area resulted in the most limiting drywell EQ temperature profile. The analysis used assumptions and initial conditions to maximize the drywell gas temperature.

In response to an NRC staff RAI, the licensee, in Supplement 7 to the EPU LAR (Reference 8), provided a comparison of the input values between the current and the EPU analysis. The values of the following input parameters remain unchanged: (a) [[

]] as the SSLB critical flow model; (b) break flow area; (c) reactor decay heat model according to ANS 5-1971 plus 2 sigma uncertainty; (d) reactor thermal power at 2%

above RTP to include instrument uncertainty effects; (e) initial containment pressure; (f) initial wetwell gas and suppression pool temperature; (g) initial drywell and wetwell relative humidities; (h) suppression pool level at its lower TS limit; (i) core spray (CS) flow to the reactor; (j) RHR heat exchanger (HX) cold side flow; (k) initial downcomer submergence height; (l) drywell-to-wetwell vent system pressure loss coefficient; (m) time from scram at which main steam isolation valves (MSIVs) start to close; (n) MSIV closure time; (o) drywell, wetwell gas space, and suppression pool volumes; and (p) initial suppression pool height.

In Supplement 7 to the EPU LAR, the licensee also provided parameters that have changed in the EPU analysis from those in the current analysis, and provided appropriate justification for the changes where the conservatism is reduced as follows:

(a) The EPU analysis used 125 °F as the initial value for the drywell gas temperature, whereas the current analysis used 145 °F. The licensee stated that the lower value gives conservative results for the peak drywell gas temperature. In an RAI, the NRC staff requested the licensee to explain why it is conservative. In the same RAI, the NRC staff requested the licensee to provide the resulting drywell gas temperature profiles for the two cases with initial drywell temperatures of 125 °F and 145 °F, while using the values of the remaining parameters and assumptions the same as in the EPU analysis. The licensee's response, in Supplement 17 to the EPU LAR (Reference 18), stated that it is conservative to use 125 °F as the initial drywell gas temperature instead of 145 °F because it leads to a higher peak drywell temperature in the analysis used for EQ evaluation. A lower initial drywell gas temperature in the analysis results in [[ ]], which leads to a higher peak pressure and higher peak temperature for the EPU limiting drywell temperature analysis with break flow area of 0.25 ft². In the same response, the licensee provided the drywell gas temperature profiles, as requested by the NRC staff. The temperature profiles show that the peak drywell gas temperature in the case with the initial drywell temperature of 125 °F is [[ ]] which is greater [[ ]] than the case with initial drywell temperature of 145 °F and peak temperature of [[ ]]

(b) In the EPU analysis, the RHR HX K-value is equal to 305 British thermal units (BTU) per second-°F) during the first hour and 500 Btu/second-°F after the first hour when the RHR cross-tie is in effect, whereas in the current analysis the K-value is equal to 270 Btu/second-°F for the entire transient.

(c) In the EPU analysis, the RHR HX revised design basis hot side flow is equal to 8600 gpm without the cross-tie in service and 4300 gpm through each HX with the cross-tie in service. In the current analysis, the HX hot side flow is equal to 9500 gpm.

(d) In the EPU analysis, the high-pressure coolant injection (HPCI) flow to the reactor is equal to [[ ]] In the current analysis HPCI flow to the reactor is [[ ]] The EPU analysis remains conservative [[

]]

(e) In the EPU analysis, the drywell holdup volume of 4416 ft^3 [[
]]

(f) In the EPU analysis, FW flow [[

]]

(g) In the EPU analysis the FW temperature is 384 °F, whereas in the current analysis the FW temperature is 383.2 °F. The higher FW temperature is more conservative.

(h) In the EPU analysis, the drywell and wetwell gas space thermal conductor parameters are revised based on re-validation of the existing conditions.

The licensee calculated a maximum drywell gas temperature of 340 °F. Based on the maximum drywell gas temperature, the licensee calculated the maximum drywell wall temperature to be 281 °F, which is the same as its design temperature. In an RAI, the NRC staff requested the licensee to explain the method of calculating the wall temperature including the assumptions used for a conservative calculation. In the same RAI, the NRC staff requested the licensee to provide the limiting drywell wall temperature obtained from dual unit interaction analysis and justify if it has the same value (i.e., 281 °F) as obtained from the single unit analysis. In response to the RAI, the licensee, in Supplement 7 to the EPU LAR (Reference 8), stated that the limiting drywell shell temperature is obtained from SSLB analysis using the [[

]] This resulted in a peak drywell wall temperature of 281 °F for both the single unit and dual unit interaction analyses. The licensee justified the same maximum drywell wall temperature for single unit and dual unit interaction analysis by stating that the maximum drywell gas temperature and pressure conditions occur prior to the initiation of drywell sprays and therefore the maximum wall temperature also occurs during the early period of the event. Postulated interruptions, which may occur in the drywell spray operation due to "dual unit interaction," would produce temporary increases in the drywell gas temperature and pressure and consequently drywell wall temperature. However, these interruptions would occur later in the event when the non-accident unit reactor has depressurized below the 450 psig pressure required for the generation of a LOCA signal from the non-accident unit. The NRC staff finds the licensee's justification acceptable.

Long-Term Wetwell Gas Temperature Response Analysis

The licensee calculated the wetwell gas space temperature by mechanistically modeling the heat and mass transfer between the suppression pool and the wetwell gas space. The calculated peak temperature for RSLB DBLOCA under EPU conditions from single unit analysis is 181 °F, and from dual unit interaction analysis is 184 °F which are less than the wetwell design temperature of 281 °F.

The licensee provided an evaluation of the non-applicability of General Electric (GE) Safety Communication (SC) 06-01 (Reference 99) for PBAPS, Units 2 and 3. The potential issue described in the safety communication is that a single failure that eliminated an RHR HX could prove more limiting than the typically analyzed scenario of the single failure of an entire AC electrical power source. The licensee stated that because of the different configuration of the RHR system, GE Safety Communication SC 06-01 has been determined to be non-applicable.

Long-Term Suppression Pool Temperature Response Analysis

The NRC staff evaluation of the suppression pool temperature response and the ECCS and containment heat removal pumps net positive suction head (NPSH) evaluation based on the temperature response is provided in Sections 2.6.5.1 and 2.6.5.2 of this SE.

Local Suppression Pool Temperature with Safety/Relief Valve Discharge

NUREG-0783 (Reference 91) specifies a local pool temperature limit for safety/relief valve (SRV) discharge because of concerns resulting from unstable condensation observed at high pool temperatures in BWRs without quenchers. PBAPS, Units 2 and 3, have T-quenchers to mitigate the SRV loads. The licensee evaluated the peak suppression pool temperature, in accordance with the NUREG-0783 criteria, and demonstrated a minimum local sub-cooling of approximately 20 °F at the SRV quencher. This ensures that the discharged steam is condensed and that the possibility of potential steam ingestion into the ECCS pump suction is eliminated. The NRC staff finds the licensee's evaluation for local suppression pool temperature with SRV discharge under EPU conditions acceptable.

Drywell to Wetwell Steam Bypass Leakage

The drywell-to-wetwell steam bypass leakage acceptance criteria for PBAPS, Units 2 and 3, is not affected by EPU and remains the same as in the current licensing basis, which is verified by TS surveillance requirement 3.6.1.1.2.

Containment Dynamic Loads

The containment design basis includes acceptable response of the containment to hydrodynamic loads associated with the discharge of reactor steam and drywell nitrogen into the suppression pool following a DBLOCA or the discharge of reactor steam following actuation of the SRVs. In NUREG-0661 (Reference 98), the NRC approved the long-term program for the containment hydrodynamic loads for Mark I containments generically defined in GE Licensing Topical Report NEDO-21888 (Reference 97). The licensee addressed the PBAPS, Units 2 and 3, plant-specific dynamic loads using the NRC-approved methods given in NUREG-0661. The following loads were addressed as discussed below:

- LOCA Loads
- SRV Loads

- LOCA Pressure and Temperature Loads

LOCA Loads:

The RSLB is the most limiting break for LOCA containment loads. The key parameters are the transient drywell and wetwell pressures, vent flow rates, and suppression pool temperature obtained from the short-term RSLB DBLOCA analysis. The LOCA-induced loads are vent thrust loads during vent clearing, pool swell loads, condensation oscillation (CO) loads, and chugging loads. Vent clearing refers to the discharge of water into the downcomers caused by drywell pressurization during the short-term period from the RSLB DBLOCA.

For the CO and chugging loads, the licensee stated that the EPU short-term containment response conditions are within the range of test conditions used to define these loads. Therefore, EPU does not impact the current CO and chugging loads.

For the pool swell loads, the licensee confirmed that the current load definition results bound the EPU pool swell loads. Therefore, EPU does not impact the current pool swell loads.

For the vent thrust loads, the licensee stated that under EPU conditions, these loads were calculated to be less than the plant-specific values calculated during the Mark I Containment long term program at all locations, except at four locations where they exceeded by less than 2.5%. However, the licensee further stated that there was margin to the allowable stress limits.

GE Licensing Topical Report NEDO-21888 (Reference 97) defines the onset and duration times for chugging based on break size. The chugging phenomena following an intermediate size and small size break begins at 5 seconds and 300 seconds, respectively, after the break and ends when the reactor pressure is equal to or below the drywell pressure when the vent flow stops (i.e., last for approximately 900 seconds). The method of vessel depressurization is by using manual initiation of the automatic depressurization system (ADS) and does not credit operation of drywell sprays. The licensee stated that the emergency operating procedures require initiation of drywell sprays before the wetwell pressure exceeds 9.0 psig. The EPU containment analysis shows that the wetwell pressure exceeds 9 psig before 900 seconds following initiation of the event. The licensee stated that the drywell sprays will rapidly reduce the drywell pressure and therefore stop chugging. The NRC staff finds the licensee's conclusion confirming that the chugging duration times used in the original PBAPS load combinations remain applicable and bounding for operation under EPU conditions acceptable.

SRV Loads:

The containment design considers the dynamic loads on the suppression pool due to the discharge of steam from the SRVs as a part of its design basis. The SRV discharge line loads, suppression pool boundary pressure loads, and the drag loads on the submerged structures in the suppression pool are the loads to be evaluated during the initial and subsequent SRV actuations under EPU conditions. These loads depend on: (1) the SRV opening setpoint pressure; (2) the initial air and water volumes in the SRV discharge line; (3) SRV discharge line geometry; (4) suppression pool geometry; and (5) the configuration of the submerged structures. The licensee evaluated these loads for initial SRV actuation, and subsequent SRV actuation. The licensee stated that for the initial SRV actuation the parameters will not change, and therefore the loads due to initial actuation are not impacted by the EPU. The loads due to subsequent SRV actuations depend primarily on the SRV discharge line reflood height at the time of SRV opening and SRV setpoints. The number of SRV cycles will increase with EPU due to a higher steaming rate at increased decay power levels. The licensee stated that EPU will reduce the time between subsequent actuations. In Supplement 7 to the EPU LAR, the licensee stated that the calculated bounding value for the time elapsed between the closing and the subsequent actuation is 7.25 seconds in the current analysis and 6.6 seconds for the EPU analysis. The licensee referred to GE report NEDE-24555-P, Revision 2, "Mark I Containment Program Application Guide 9, Safety Relief Valve Discharge Line Reflood Transient," which describes the two limiting SRV load analysis cases designated as C.3.1 and C.3.3, which provides the acceptance criteria. [[

]] Therefore, the current and EPU analysis meet the criterion allowing the second peak of the SRV discharge line water level. The NRC staff accepts the licensee's evaluation and agrees that the SRV logic modification for the EPU is not required [[

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LOCA Pressure and Temperature Loads:

The licensee stated that the current PBAPS plant-specific LOCA pressure and temperature loads were obtained from the PBAPS Plant Unique Load Definition report generated during the Mark I Long Term Program (Reference 100). The maximum values of 30.6 psig for the wetwell pressure and 155 °F for the suppression pool temperature, reported in Reference 100, were obtained from the intermediate break accident (IBA) analysis. The licensee also stated that in the current analysis, the design load combinations with the thermal loads are based on the IBA analysis because they are bounding.

For the EPU, the licensee evaluated the pressure and temperature loads induced from DBLOCA, IBA, and small break accident (SBA) events for input to the structural analysis. The IBA and SBA events were evaluated at 102% EPU RTP using the same initial conditions and assumptions as in the current analysis. The results for peak wetwell and suppression pool temperature under EPU conditions for the SBA and IBA are 148 °F and 155 °F, respectively (Reference 8). The results of the PBAPS EPU analysis show that all drywell and wetwell pressure and temperatures at EPU conditions are bounded by the values of Reference 100, with the exception of the peak suppression pool temperature for the SBA. At EPU conditions, the SBA peak wetwell and suppression pool temperature is 148 °F, which does not bound the Reference 100 result of 122 °F. However the current suppression pool temperature 155 °F for IBA bounds the EPU SBA peak suppression pool temperature 148 °F. Therefore, the current LOCA pressure and temperature load analysis bound the analysis under EPU conditions. The NRC staff finds licensee's justification that the current containment dynamic load analysis remains valid acceptable because it bounds the analysis for EPU conditions.

Summary

The following is a summary of the results, derived from the above technical evaluation, related to the acceptance criteria given in the NRC regulatory requirements for the primary containment functional design under EPU conditions:

- The ESF SSCs inside the containment will be protected from dynamic loads, short and long term effects of equipment failures and LOCAs.

- The current containment design, along with the modified heat removal system, will maintain the required containment integrity during the effects of worst reactor coolant pressure boundary break, as long as the conditions require.

- The current containment design along with the modified heat removal systems accommodate, without exceeding the design leakage rate, the pressures and temperatures resulting from the largest energy release following a LOCA.

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 final GDC-64 and draft GDCs 10, 12, 40, 42 and 49, 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 operation at EPU conditions, and the resulting increase in pressurization. The NRC's acceptance criteria for subcompartment analyses are based on: (1) draft GDCs 40 and 42, insofar as they require that protection be provided for ESFs against the dynamic effects that might result from plant equipment failures, as well as the effects of a LOCA; and (2) draft GDC-49, insofar as it requires that the containment be designed so that the containment structure can accommodate, without exceeding the design leakage rate, the pressures and temperatures resulting from the largest credible energy release following a LOCA. Specific review criteria are contained in SRP Section 6.2.1.2.

Technical Evaluation

The annular region between the outside vertical wall of the RPV and the inside of the sacrificial shield wall (SSW) is a containment subcompartment to be analyzed for differential pressure loads due to high energy line breaks (HELBs). The SSW is a reinforced concrete cylindrical structure surrounding the RPV that provides thermal and radiation shielding. It is designed to withstand the maximum differential pressure that would develop across the wall as a result of a HELB between the RPV and the SSW. The licensee's analysis calculated the differential pressure across the SSW due to the limiting RSLB under the EPU conditions. The licensee also evaluated the stagnation pressure in the annulus, and the jet impingement (JI) pressure on the shield plugs in the shield wall penetrations resulting from a feedwater line break (FWLB) pressurizing the SSW annulus.

The SSW differential pressure analysis under EPU conditions due to the limiting RSLB LOCA was performed by conservatively assuming the critical break flow as a subcooled liquid flow, instead of a saturated liquid flow, as in the current analysis. The critical break mass flow was calculated under the EPU condition in the maximum extended load line limit analysis (MELLLA) operating domain. The analysis results indicated that the differential pressure across the SSW increased from its current value of 34.0 psid to 59.2 psid. The design limit is 72.0 psid.

In an RAI, the NRC staff requested the licensee to provide a more detailed description of the SSW annulus pressurization and the SSW plug JI analysis for a FWLB inside the annulus. In response to the RAI, in Supplement 7 to the EPU LAR (Reference 8), the licensee stated that FWLB analyses were performed for both normal and off-rated conditions to ensure that the entire operating domain is covered. The licensee evaluated the following off-rated conditions: (1) 102% EPU RTP, rated core flow, and at final FW temperature reduction of 90 °F; (2) 102% EPU RTP, increased core flow, and at final FW temperature reduction of 90 °F; (3) 102% EPU RTP, increased core flow, and at normal FW temperature; (4) minimum pump speed (MPS) (see PUSAR Figure 1-1, Point 'C' which corresponds to 38% core flow and 54.9% RTP), and at normal FW temperature; and (5) MPS and at reduced FW temperature. In a FWLB, the FW that flashes into steam pressurizes the SSW annulus. The licensee calculated the SSW plug differential pressure by adding the static pressure in the annulus caused by the mass flux from the broken pipe and the high velocity JI pressure load on the shield plug.

The following assumptions were made for the analysis: (1) used a high value of 1.45 for the thrust coefficient to determine a conservative JI pressure load, which conservatively bounds the results based on the Henry-Fauske model specified in ANS/ANSI 58.2-1988, "Design Basis for Protection of Light Water Nuclear Power Plants Against the Effects of Postulated Pipe Rupture;" (2) used Moody's sub-cooled slip flow model for break critical flow which is conservative because it does not include friction losses and maximizes the mass and energy release; (3) an instantaneous guillotine break of the pipe, which conservatively maximizes the pressure in the annulus; (4) assumed the steady-state pressure in the annulus equal to the initial break pressure, which is conservative because the RPV depressurization will reduce both the static pressure as well as the JI pressure load; (5) initial reactor pressure based on the MPS case is conservatively assumed equal to the rated dome pressure, which is conservative because the reactor dome pressure is typically reduced at MPS; and (6) primary containment pressurization outside of the annulus is conservatively ignored, which is conservative because the pressurization will reduce the shield plug differential pressure.

The licensee's FWLB analysis results are as follows: (1) the SSW annulus maximum differential pressure increased from its current value of 9.2 psid to an EPU value of 9.3 psid; (2) the maximum JI pressure remained at its current value of 39.1 psid under EPU conditions; and (3) the maximum SSW plug pressure (a +b) increased from 48.3 psid to an EPU value of 48.4 psid (its design limit is 52.0 psid). The results of FWLB SSW pressure loads under EPU full power conditions bound the pressure loads at MPS off-rated conditions.

The NRC finds the licensee's RSLB and FWLB SSW annulus pressurization acceptable because the licensee used conservative assumptions and confirmed the results are within the design limits.

Summary

The following is a summary of the results, derived from the above technical evaluation, related to the acceptance criteria given in the NRC regulatory requirements for the primary containment subcompartment analysis under EPU conditions:

- The ESF SSCs inside the containment subcompartments will be protected from the dynamic effects of equipment failures and LOCAs.

- The current containment design can accommodate, without exceeding the design leakage rate, the pressures and temperatures resulting from the largest credible energy release following a LOCA.

Conclusion

The NRC staff has reviewed the subcompartment assessment performed by the licensee and the change in predicted pressurization resulting from the increased mass and energy release. The NRC staff concludes that containment SSCs important to safety will continue to be protected from the dynamic effects resulting from pipe breaks and that the subcompartments will continue to have sufficient margins to prevent fracture of the structure due to pressure difference across the walls following implementation of the proposed EPU. Based on this, the NRC staff concludes that the plant will continue to meet draft GDCs 40, 42 and 49 for the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to subcompartment analyses.

2.6.3 Mass and Energy Release

2.6.3.1 Mass and Energy Release Analysis for Postulated Loss of Coolant

Regulatory Evaluation

The release of high-energy fluid into containment from pipe breaks could challenge the structural integrity of the containment, including subcompartments and systems within the containment. The NRC staff's review covered the energy sources that are available for release to the containment and the mass and energy (M&E) 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) draft GDC-49, 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, the pressures and temperatures resulting from the largest credible energy release following a LOCA; and (2) 10 CFR Part 50, Appendix K, insofar as it identifies sources of energy during a LOCA. Specific review criteria are contained in SRP Section 6.2.1.3.

Technical Evaluation

For the short-term drywell pressure response, the licensee used the LAMB computer code for M&E release and the M3CPT computer code for the containment response. The power uprate methods approved by the NRC permit the use of either the M3CPT computer code or the LAMB computer code to calculate the M&E release from the postulated pipe break into the drywell (Reference 20).

The M&E release following a LOCA in containment is discussed above in SE 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 M&E release methods are therefore acceptable.

Summary

The following is a summary of the results, derived from the above technical evaluation, related to the acceptance criteria given in the NRC regulatory requirements for the primary containment M&E release analysis for postulated LOCAs under EPU conditions:

- The current containment design can accommodate, without exceeding the design leakage rate, the pressures and temperatures resulting from the largest credible energy release following a LOCA.

- The energy sources during a LOCA are properly identified and analyzed using NRC-approved methods.

Conclusion

The NRC staff has reviewed the licensee's M&E release assessment and concludes that the licensee has adequately addressed the effects of the proposed EPU and appropriately accounts for the sources of energy identified in 10 CFR Part 50, Appendix K. Based on this, the NRC staff finds that the M&E release analysis meets the requirements in draft GDC-49 for ensuring that the analysis is conservative. Therefore, the NRC staff finds the proposed EPU acceptable with respect to M&E 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 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; and (2) draft GDC-4, insofar as reactor facilities shall not share systems or components unless it is shown safety is not impaired by the sharing. Specific review criteria are contained in SRP Section 6.2.5.

Technical Evaluation

The PBAPS, Units 2 and 3, containments are inerted with nitrogen. The NRC revised 10 CFR 50.44, "Combustible gas control for nuclear power reactors," on September 16, 2003. The changes eliminated the requirements for hydrogen recombiners for nitrogen inerted containments and relaxed the requirements for hydrogen and oxygen monitoring in containment. The revised regulation no longer defines a DBLOCA hydrogen release, and eliminates requirements for hydrogen control systems to mitigate such a release. The installation of hydrogen recombiners and/or vent and purge systems required by 10 CFR 50.44(b)(3) was intended to address the limited quantity and rate of hydrogen generation that was postulated from a DBLOCA. License Amendments 256 and 259 for PBAPS, Units 2 and 3, respectively, issued in 2005 (Reference 94), eliminated the requirements for the hydrogen and oxygen monitors. License Amendments 274 and 278 for PBAPS, Units 2 and 3, respectively, issued in 2010 (Reference 95), eliminated the requirements for the hydrogen recombiners (i.e., Containment Atmospheric Dilution system). Therefore operating under EPU conditions does not affect the current combustible gas control system.

Summary

The following is a summary of the results, derived from the above technical evaluation, related to the acceptance criteria given in the NRC regulatory requirements for the combustible gas control inside the containment under EPU conditions:

- As required in 10 CFR 50.44, the capability for controlling combustible gas concentrations in the containment is maintained during normal operating and postulated accident conditions.

- As required in draft GDC-4, the PBAPS, Units 2 and 3, do not share systems or components for combustible gas control inside containment.

Conclusion

The NRC staff has reviewed the licensee's assessment related to combustible gas and concludes that the plant will continue to have sufficient capabilities consistent with the requirements in 10 CFR 50.44 and draft GDC 4, as discussed above. Therefore, the NRC staff finds the proposed EPU acceptable with respect to combustible gas control in containment.

2.6.5 Containment Heat Removal

Regulatory Evaluation

Fan cooler systems, spray systems, and residual heat removal (RHR) systems are provided to remove heat from the containment atmosphere and from the water in the containment wetwell. The NRC staff's review in this area focused on: (1) the effects of the proposed EPU on the analyses of the 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 draft GDCs 41 and 52, insofar as they require that a containment heat removal system be provided, and that its function shall be to prevent exceeding containment design pressure under accident conditions. Specific review criteria are contained in SRP Section 6.2.2, as supplemented by RG 1.82 (Reference 102).

Technical Evaluation

2.6.5.1 Suppression Pool Temperature Response Analysis

PBAPS, Units 2 and 3, share four emergency diesel generators (EDGs) between the two units. Because of the sharing of EDGs, the suppression pool temperature response is affected when events would occur simultaneously in the two units. The licensee performed: (1) single unit analyses for events occurring in one unit only; and (2) dual unit interaction analyses considering events occurring simultaneously in both units. For the EPU conditions, the licensee took credit for the following significant modifications that are being performed in support of the EPU as described in Attachment 9 to the EPU LAR: (1) RHR heat exchanger (HX) cross-tie modification; and (2) high-pressure service water (HPSW) cross-tie modification. The cross-tie modifications will allow two RHR HXs to be supplied from one RHR pump and the ability to align HPSW pumps from the opposite division to provide cooling water to the two RHR HXs. The licensee performed single unit and dual unit interaction suppression pool temperature response analysis for: (1) RSLB DBLOCA; (2) SSLB LOCA; and (3) loss of RHR normal shutdown cooling (NSDC) event by taking credit of these modifications.

As discussed in Supplement 7 to the EPU LAR (Reference 8), for the EPU suppression pool temperature response analysis for NPSH, the licensee used the same conservative inputs and

assumptions as stated in the EPU drywell gas temperature response analysis except for the following: [[
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Single Unit Analysis for RSLB DBLOCA Event

This single unit analysis considered a RSLB DBLOCA event concurrent with loss of offsite power (LOOP) in one unit only and the worst case single active failure of one EDG. The analysis was performed at 102% RTP, using ANS/ANSI-1979 plus 2-sigma decay heat model and additional actinides and activation products per GE Service Information Letter (SIL) 636 (Reference 96). The licensee assumed no operator action for the first 10 minutes into the event. It is assumed that the operator takes manual control at 10 minutes after the event initiation and aligns one RHR loop (one RHR pump, one RHR HX, and one HPSW pump) to provide containment cooling with a flow rate of 8600 gpm. At 1 hour after event initiation, the RHR HX cross-tie is placed in service, which results in a containment cooling configuration of one RHR pump flow of 8600 gpm split between two RHR HXs. The RHR HX cross-tie modification results in a significant increase in the capacity of a single RHR pump to cool the containment and suppression pool. The three modes of containment cooling evaluated are suppression pool cooling (SPC), containment spray cooling (CSC), and coolant injection cooling (CIC).

In an RAI, the NRC staff requested the licensee to describe the testing frequency, the current and the EPU acceptance criteria for the RHR HX performance testing, and the basis of the EPU acceptance criteria. The licensee was also requested to describe the event that requires the highest heat removal rate of the RHR HX under EPU conditions, and confirm that the HX heat removal rate acceptance criteria bounds the required heat removal capacity for the most limiting event. In its response in Supplement 7 to the EPU LAR EPU (Reference 8), the licensee stated that each of the four RHR HXs in each PBAPS unit is tested once every 4 years. Both current and EPU acceptance criteria are based on the HX performance assumed in the respective design basis analyses. The current acceptance criterion is based on a single RHR HX K-value of 270 BTU/sec °F. The EPU acceptance criterion will be based on a single RHR HX K-value of 305 BTU/sec °F. The same HX performance (fouling resistance) corresponding to a single RHR HX K-value of 305 BTU/sec °F at 8600 gpm RHR flow rate and 4500 gpm HPSW flow rate was used in all analyses such that there is no substantive difference in the HX condition (fouling resistance) from one event to the other. The licensee confirmed that the HX performance acceptance criterion reflects the required heat removal capacity for the most limiting event. The licensee stated that historical test data shows a minimum K-value of approximately 330 Btu/sec °F, including test measurement uncertainty.

The licensee calculated 186 °F as the peak bulk suppression pool temperature at EPU RTP for the RSLB DBLOCA.

The NRC staff has determined that the licensee used conservative assumptions, considered worst single active failure and a LOOP for the analysis, and revised the single RHR HX performance test acceptance criterion from the current K-value of 270 BTU/sec °F to the EPU K-value of 305 BTU/sec °F assuming the same hot and cold side flows, as used in the analysis. Therefore, the NRC staff finds the licensee's evaluation acceptable.

Dual Unit Interaction Analysis with RSLB DBLOCA

The licensee's dual unit interaction analysis simultaneously considered RSLB DBLOCA in one unit, concurrent LOOP in both units, and loss of one EDG as the worst case single active failure, therefore sharing of the remaining three EDGs by both units. In the two sub-sections below, the RSLB DBLOCA unit is described as the "accident unit" and the other unit as the "non-accident unit." As a result of the LOOP, drywell cooling function of the non-accident unit will be lost resulting in a high drywell pressure in that unit. An automatic LOCA signal will be generated in the non-accident unit due to high drywell pressure, if it is concurrent with a low RPV pressure. When the RPV is depressurized below 450 psig, the LPCI mode of RHR system is initiated. In order to avoid tripping of a RHR pump of the accident unit:

(1) The current logic prevents simultaneous loading of both units RHR pumps on a shared EDG to protect it from overloading.

(2) The current abnormal operating procedures (AOPs) require the operators to secure the RHR and HPSW pumps on the accident unit prior to depressurizing the non-accident unit below 500 psig. This assures restoration of the RHR system in the accident unit, after RHR is initiated in the LPCI mode in the non-accident unit and adequate core cooling is verified.

Accident Unit Response:

The licensee performed the accident unit RSLB DBLOCA suppression pool temperature response analysis for this scenario the same as for the single unit RSLB DBLOCA, as described above, except for a 10-minute interruption of containment cooling because of the dual unit interaction. The interruption is assumed to occur when the accident unit suppression pool temperature is 10 °F below the peak suppression pool temperature that would be experienced by the accident unit if there was no containment cooling interruption. In Supplement 7 to the EPU LAR (Reference 8), the licensee provided the basis for the timing of the assumed interruption of containment cooling at 10 °F below what the peak suppression pool temperature would be if no interruption had occurred. It is based on the manual depressurization and cooldown of the non-accident unit reactor at a maximum rate of 100 °F/hr. The earliest the unit would reach 450 psig and generate the LOCA signal is at time 1 hour and 10 minutes, as assumed in the analysis. The licensee also stated that the assumed timing is conservative because the impact of the interruption in the SPC is more severe before the suppression pool reaches its peak temperature, which is approximately 2.9 hours. The licensee further stated that the plant operators ensure adequate NPSH is maintained assuming a 10 °F rise in the suppression pool temperature at the time of the interruption. After the 10-minute interruption, the analysis assumes the accident unit containment cooling is restored with the same configuration as existed prior to the interruption.

In order to provide margin to reach the 450 psig LOCA signal setpoint, the current procedures guide the operators to depressurize the non-accident reactor at a slower rate than the maximum allowed rate of 100 °F/hr and stop when reactor pressure reaches 500 psig. The controlled depressurization and the timing of generation of the LOCA signal in the non-accident unit, and subsequent interruption in SPC in the accident unit, is coordinated between both unit operators. The licensee stated that the current procedural guidance instructs the operators to consider the rise in suppression pool temperature and reduction in NPSH for restarting the RHR pumps on the accident unit after the interruption. The licensee will enhance operator guidance for EPU to expect a 10 °F rise in suppression pool temperature due to the interruption and to ensure adequate NPSH is available for the ECCS pumps.

The licensee was also requested to provide a realistic expected containment cooling interruption time during an RSLB DBLOCA scenario compared to the 10-minute assumption used in the analysis. The licensee stated that an exact interruption time is not available; however, the assumed 10-minute SPC interruption time is conservative because the RHR and HPSW system alignment actions are performed from the main control room, and licensed operators estimated approximately 5 to 10 minutes to restore containment cooling.

The licensee calculated 187.2 °F as the peak bulk suppression pool temperature at EPU for the RSLB DBLOCA in the accident unit.

The NRC staff considers the licensee's accident unit suppression pool temperature response analysis acceptable because: (1) the assumption of the dual unit interaction LOCA signal 10 °F below the peak pool temperature, if no SPC interruption had occurred, conservatively evaluates the suppression pool temperature response; and (2) the proposed EPU enhancement in the operator guidance will assure that the suppression pool temperature remains within the limits for the ECCS pump NPSH.

Non-Accident Unit Response:

Using normal shutdown cooling, the licensee evaluated the suppression pool temperature response and capability to achieve cold shutdown within 36 hours for the non-accident unit, during an RSLB DBLOCA in the accident unit concurrent with LOOP in both units, assuming concurrent non-accident unit reactor scram and isolation and a single active failure of loss of one EDG. For this scenario, the licensee's non-accident unit analysis conservatively assumed: (1) 102% of EPU RTP; (2) ANS/ANSI 5.1-1979 plus 2-sigma decay heat model; (3) additional actinides and activation products per GE SIL 636 (Reference 96); (4) drywell cooling fans not available; (5) NSDC of RHR is not available because of loss of one EDG; and (6) no credit for the CST volume. The reactor depressurization and cooldown at the rate of 100 °F/hr is accomplished manually by operators while the makeup water is provided by HPCI. The containment cooling mode assumed in the analysis is the SPC mode of RHR starting at 1 hour from reactor scram. Because of the LOOP, the drywell cooling function is lost. The increase in drywell pressure satisfies one of the two conditions for the initiation of LOCA signal in less than 1 hour. However, for preventing RHR operation in the LPCI mode, the generation of a LOCA signal within one hour of scram should be avoided. This is achieved by manual depressurization and cooldown of the reactor at the rate of 100 °F/hr when suppression pool temperature reaches 110 °F, but no sooner than 10 minutes after reactor scram. It results in the non-accident reactor reaching 450 psig in approximately 1 hour and 10 minutes after reactor scram and thereby satisfying the remaining condition of generating the LOCA signal. The licensee varied the timing of appearance of the non-accident unit LOCA signal to provide a conservative accident unit suppression pool temperature response for each accident and event. The LOCA signal will automatically initiate the CS flow, realign the RHR pump in the LPCI mode and stop the HPSW flow. After 10 minutes in this mode of operation, operators will start the HPSW flow to the RHR HX, and realign the RHR pump in the SPC mode.

The licensee stated that the results of this evaluation of the non-accident unit response is applicable and bounding for small break LOCAs and other accidents and events on the accident unit because the scenario includes a bounding dual unit interaction and uses the minimum equipment available to reach cold shutdown. The NRC staff requested in an RAI that the licensee list other accidents and events for which this dual-unit interaction analysis is bounding, and provide reasons that it is bounding. In response to the RAI, the licensee, in Supplement 7 to the EPU LAR (Reference 8), stated that the other accident and events are DBAs, an SSLB LOCA, a station blackout (SBO) event, and an Appendix R Fire event. For these accidents and events, the licensee made the following conservative assumptions for the non-accident unit shutdown analysis under a LOOP: (1) used design basis and/or TS limiting values as inputs instead of nominal values; (2) used only one RHR pump and one HPSW pump for SPC; (3) no credit is taken for use of the RHR cross-tie modification, which would be available to the non-accident unit for all accidents/special events in the other unit except DBLOCA or SBO; and (4) conservatively assumed two 10-minute interruptions in SPC in the non-accident unit to bound all accidents and events; one interruption due to the generation of a LOCA signal in the accident unit and a second interruption when the non-accident unit RPV is depressurized. This assumption is valid for small steam breaks and other events because the LOCA signal is generated later, after SPC is in service in the non-accident unit. This assumption also remains valid for DBLOCA, intermediate break LOCAs, and larger steam break LOCAs because of the early generation of the LOCA signal, prior to initiation of SPC in the non-accident unit. The NRC staff agrees that using the above assumptions provides a bounding non-accident unit shutdown cooling analysis.

The licensee calculated 203.8 °F as the peak bulk suppression pool temperature, and 35.1 hours as the time for the reactor water to reach less than the TS cold shutdown temperature of 212 °F.

The NRC staff finds the licensee's evaluation acceptable, because: (1) the licensee used conservative assumptions; (2) the manual control of the depressurization of the non-accident unit assures that the LOCA signal doesn't occur immediately, prior to, or following the LOCA signal on the accident unit to avoid potential tripping of the RHR pump operating in the accident unit; (3) the current AOPs require the operators to secure the RHR and HPSW pumps on the accident unit prior to depressurizing the non-accident unit below 500 psig to assure continuous operation of RHR system in the accident unit, except for a brief period of time of approximately 10 minutes, which was analyzed and shown to be acceptable.

Single Unit Analysis for SSLB LOCA

This licensee's single unit analysis considered an SSLB LOCA concurrent with a LOOP in one unit, and a worst case single active failure of one EDG. The licensee performed the analysis at 102% EPU RTP, and using the ANS/ANSI-1979 plus 2-sigma decay heat model and additional actinides and activation products per GE SIL 636 (Reference 96). The analysis evaluates the suppression pool temperature response, EQ profiles in the drywell, and confirms the ability to achieve cold shutdown within 36 hours following initiation of the event. The licensee analyzed break sizes of 0.01 ft^2, 0.05 ft^2, 0.1 ft^2, 0.25 ft^2, 0.50 ft^2 and 1.00 ft^2 and determined 0.01 ft^2 as the most limiting break size with respect to suppression pool temperature response. For RPV makeup, one loop of CS (two pumps) and three RHR pumps in the LPCI mode are available. In response to an NRC staff RAI, the licensee, in Supplement 7 to the EPU LAR (Reference 8), stated that although there is no LOCA signal early in the SSLB event, the analysis assumed that all available ECCS pumps automatically start with a minimum delay of approximately 15 seconds. This is conservative because early operation of the these pumps adds additional heat to the containment. LPCI would not occur during the first 10 minutes because the RPV pressure is still higher than the pump head. At 10 minutes into the accident, the operator turns off two out of the three RHR pumps and realigns the third RHR pump to provide containment cooling with a flow of 8600 gpm through one RHR HX and one HPSW pump providing cooling flow. When the wetwell pressure reaches 9 psig, operators switch the RHR from SPC mode and wetwell spray mode to drywell spray mode and wetwell spray mode. To calculate the most limiting drywell temperature response, the licensee did not credit HPCI for reactor makeup for the first 10 minutes to avoid suppression of steam generation in the RPV by the HPCI system cold water, and also avoiding removal of reactor steam by the HPCI turbine. The procedure assumed in the analysis used operator-controlled reactor cooldown at the rate of 100 °F per hour after the suppression pool temperature reaches 110 °F but not earlier than 10 minutes into the event. The containment cooling is performed by operators using drywell and wetwell sprays and using the RHR HX cross-tie. In the last part of the cooldown, the reactor is flooded up to the main steam lines, ADS valves are opened to establish alternate shutdown cooling (ASDC) mode, while the containment cooling is continued using the drywell and wetwell sprays.

The licensee calculated 187 °F as the peak bulk suppression pool temperature, and a reactor cold shutdown temperature less than 200 °F in 36 hours, which is below the TS cold shutdown temperature of 212 °F.

The NRC staff finds the licensee's evaluation acceptable because the licensee used conservative assumptions for the suppression pool temperature response analysis for the most limiting SSLB size.

Dual Unit Interaction Analysis for SSLB LOCA

The licensee's dual unit interaction analysis simultaneously considered a SSLB LOCA in one unit, a concurrent LOOP in both units, and loss of one EDG as the worst case single active failure; therefore, sharing of remaining three EDGs by both units. In the two subsections below, the SSLB LOCA unit is called the "accident unit" and the other unit is called the "non-accident unit." The licensee analyzed the break size of 0.01 ft^2 which is the most limiting break size with respect to suppression pool temperature response.

Accident Unit Response:

The licensee's accident unit analysis assumes the same sequence in the accident unit as for the single unit analysis, except for including two containment cooling interruptions of 10-minutes each. The first 10-minute interruption occurs when a LOCA signal, based on a combination of high drywell pressure and low reactor pressure, occurs in the accident unit. The second 10-minute interruption is assumed when the operator verifies (using the NPSH curves in the emergency operating procedures (EOPs)) that a margin of 10 °F in the suppression pool temperature exists on the accident unit, before depressurizing the non-accident unit reactor below 450 psig.

The licensee calculated 187.6 °F as the peak bulk suppression pool temperature, and a reactor cold shutdown temperature of less than 200 °F in 36 hours, which is below the TS cold shutdown temperature of 212 °F.

The NRC staff finds the licensee's evaluation acceptable because the licensee used conservative assumptions for the suppression pool temperature response analysis for the most limiting SSLB size.

Non-Accident Unit Response:

The licensee's non-accident unit analysis assumed the following sequence of events in the non-accident unit to bring the plant to a cold shutdown condition within 36 hours: (1) manual initiation of reactor depressurization when the suppression pool temperature reaches 110 °F but no sooner than 10-minutes into the event; (2) manual initiation of SPC using one-RHR pump and one-RHR HX at 1-hour into the event; (3) generation of the high drywell pressure setpoint LOCA signal at 2 hours and 25 minutes when the reactor pressure is reduced to 450 psig (2 hours and 25 minutes is the time at which the suppression pool temperature in the accident unit would have been 10 °F below its peak value if a LOCA signal were not generated in the non-accident unit). In response to an NRC staff RAI, the licensee, in Supplement 17 to the EPU LAR (Reference 18), stated and justified that the input assumptions for the non-accident unit shutdown cooling analysis assure that the current analysis remains bounding and are independent of the events for the accident unit.

Single Unit Analysis for Loss of RHR NSDC Event

This licensee's single unit analysis considered a LOOP concurrent with loss of one division of emergency power in one unit only. The loss of one division of emergency power prevents the use of the RHR system operating in the NSDC mode, and therefore the ASDC method is used. The licensee performed the analysis for the ASDC method at 102% RTP, using the ANS/ANSI-1979 plus 2-sigma decay heat model, and additional actinides and activation products per GE SIL 636 (Reference 96). The ASDC can be performed using the CIC mode, the SPC mode, or the CSC mode, which were described by the licensee in Supplement 7 to the EPU LAR (Reference 8) as follows:

- In the CIC mode, flow of 8600 gpm, from one RHR pump, is drawn from the suppression pool, cooled through the RHR HXs, injected into the reactor, and returned to the suppression pool via the SRVs.
- In the SPC mode, flow of 6250 gpm, from one RHR pump, is drawn from the suppression pool, cooled through the RHR HXs, and returned to the suppression pool. In this mode, the RHR system is used to cool the suppression pool.
- The CSC mode is the same as the SPC mode, except the RHR system is used for containment and SPC is in the drywell and wetwell spray mode.

The licensee analyzed the CIC mode only because it has the largest heat addition to the suppression pool compared to the SPC and CSC modes. The CIC mode resulted in the most limiting peak bulk suppression pool temperature. In response to an NRC staff RAI, the licensee, in Supplement 7 to the EPU LAR (Reference 8), stated that the CIC mode results in the shortest time to cool the reactor to cold shutdown because the RPV injection flow is 8600 gpm in this mode, compared to 6250 gpm in the SPC and CSC modes, and the flow is cooled by the RHR HX. The licensee stated that the suppression pool temperature response analysis with cold shutdown achieved by the ASDC method is also applicable for a small liquid line break LOCA, wherein SPC mode is used in lieu of the CSC mode. The licensee also stated that the suppression pool peak temperature response for both of these events is bounded by the suppression pool temperature response for the limiting SSLB LOCA.

The analysis resulted in a cold shutdown bulk reactor temperature below 200 °F in 16 hours, which is below the TS definition for cold shutdown of 212 °F, and less than the acceptance limit of 36 hours. The peak bulk suppression pool temperature for this analysis at EPU conditions is 186 °F.

Dual Unit Interaction Analysis with Loss of RHR NSDC Event

In the following description, the unit having a loss of NSDC is called the "ASDC unit" and the other unit is called the "NSDC unit." The licensee's dual unit interaction analysis considered a simultaneous LOOP in both units concurrent with loss of one division of emergency power. The loss of one division of emergency power prevents the use of the RHR system operating in the NSDC mode, and therefore the ASDC method is used in the ASDC unit. The licensee performed the analysis for ASDC mode at 102% RTP, using the ANS/ANSI-1979 plus 2-sigma decay heat model, and additional actinides and activation products per GE SIL 636 (Reference 96). The licensee summarized the procedure, including operator actions, assumed in the analysis, which includes two containment cooling interruptions each lasting for 10 minutes, which is conservative. In response to an NRC staff RAI, the licensee, in Supplement 7 to the EPU LAR (Reference 8), stated that the CIC mode results in the shortest time to cool the reactor to cold shutdown because the RPV injection flow is 8600 gpm in this mode, compared to 6250 gpm in the SPC and CSC modes, and is cooled by the RHR HX.

The analysis results in a cold shutdown bulk reactor temperature below 200°F in 16 hours, which is less than the TS definition for achieving cold shutdown temperature of 212 °F in 36 hours. The calculated peak bulk SPC temperature at EPU conditions is 186.7 °F for the ASDC unit.

In Supplement 17 to the EPU LAR (Reference 18), the licensee stated and justified that the input assumptions for the NSDC Unit shutdown cooling analysis assure that the current analysis remains bounding and is independent of the ASDC Unit.

2.6.5.2 ECCS and Containment Heat Removal Pump NPSH Analysis

The ECCS and containment heat removal pumps are the RHR and CS system pumps. NPSH analysis for these pumps consists of verifying adequate NPSH margin exists for their satisfactory operation during DBAs and non-design basis events. The NPSH margin is defined as the difference between the NPSH available (NPSHa) at the pump suction inlet, and NPSH required (NPSHr) during pump operation. The parameters affecting the NPSHa are suppression pool level, suppression pool temperature, pump flow rate, suction strainer head loss, and suction pipe frictional loss. The NPSHr, provided by the pump manufacturer, denominated as NPSHr3%, is obtained by shop testing of the pump under controlled conditions. The NPSHr for the pump at the reactor site, denominated as NPSHreff, is adjusted by including uncertainty due to differences between the shop testing conditions and the plant operating conditions. References 92 and 93 provide NRC staff guidance: (1) for evaluating the uncertainty in the NPSHr3% due to these differences; (2) on the use of containment accident pressure (CAP) for the evaluation of the NPSHa for the ECCS and the containment heat removal pumps; and (3) permissible time for pump operation in the zone of maximum erosion (i.e., NPSH margin ratio between 1.2 to 1.6, less than 100 hours).

The DBAs analyzed are: RSLB DBLOCA and SSLB LOCA. Reference 93 provides the following relation between the NPSHr3%, NPSHreff and the uncertainty in NPSHr3%:

NPSHreff = (1 + uncertainty) x NPSHr3%

The non-design basis events analyzed are: Loss of RHR NSDC, stuck-open relief valve (SORV) with RPV Isolation, Appendix R Fire, SBO, and ATWS. For non-design basis events, Reference 93 provides the following relationship:

NPSHreff = NPSHr3%

The licensee calculated NPSH margins assuming pump flow rates that meet or exceed the RHR and CS pump operational requirements for the analyzed accidents and events. For the NPSH analysis for all accidents and events, the licensee conservatively increased the pump flow rates, except for the RHR pump flow rates for the RSLB DBLOCA short-term analysis, by a factor of $1/\sqrt{0.97}$ (1.015) to account for the possible reduction of pump total developed head by 3%, when NPSHr3% curves are utilized for comparison to NPSHa. For the RSLB DBLOCA NPSH short term analysis, the licensee conservatively increased the RHR flow rate by approximately 3% above the assumed flow rate in the containment safety analysis. The licensee evaluated the ECCS strainer design debris load methodology in Reference 90 and determined that it is not impacted under EPU conditions. Therefore, consideration of ECCS suction strainer debris loading for the NPSH evaluations under EPU conditions is consistent with the current analysis for the RSLB DBLOCA event. The licensee's SSLB LOCA and anticipated transient without scram (ATWS) events also include ECCS suction strainer debris loading in their NPSH analysis.

Following the guidance in Reference 93 and RG 1.82 (Reference 102), assuming the maximum wetwell pressure as 14.638 psia for all accidents and events under EPU conditions, the licensee did not take any credit for CAP in the NPSHa calculation. The current licensing basis relies on CAP, however, the RHR cross-tie modification undertaken by the licensee for EPU conditions allowed the licensee's NPSHa calculation to not to rely on CAP.

Reference 93, Section 6.6.8, provides NRC staff guidance stating that the pump operating time in the zone of maximum erosion rate, where the "NPSH margin ratio" (NPSHa/NPSHr3%) is between 1.2 and 1.6, should be limited unless operating experience, testing, or analysis justifies a longer time. The guidance further states that realistic calculations should be used to determine the time within this zone of NPSH margin ratio values. The NRC staff evaluation of the NPSH analysis for the accidents and events performed by the licensee and the results of NPSH margin and time of operation below the NPSH margin ratio of 1.6 is discussed below.

RSLB DBLOCA NPSH Analysis

The RSLB DBLOCA NPSH analysis consisted of short-term analysis, up to 10 minutes from accident initiation, followed by the long-term analysis. The licensee made the following assumptions: (1) assumed RHR and CS pump flows conservatively greater than assumed in the suppression pool temperature response safety analysis; (2) included debris loading in suction strainer head loss; and (3) followed guidance in RG 1.82 for determining the suppression pool drawdown water level for the short and long term analyses. Table 2.6.5.2-1 below shows the licensee's results extracted from PUSAR Table 2.6-5.

Table 2.6.5.2-1
RSLB DBLOCA NPSH Analysis Results

Analysis	Peak Suppression Pool Temperature (°F)	Pump	Uncertainty in NPSHr3% (%)	NPSH Margin [NPSHa - NPSHreff] (ft)	Operating Time in the NPSH Margin Ratio 1.6 (hours)
Short-Term	159	RHR	21	1.72	0.15
		CS	21	6.29	0.1
Long-Term Single Unit	186	RHR	21	3.85	<6
		CS	21	0.78	<15
Long-Term Dual Unit Interaction	187.2	RHR	21	3.33	<7
		CS	21	0.26	<15

The NRC staff finds the RSLB DBLOCA NPSH evaluation acceptable because by using conservative inputs and assumptions and without the use of CAP, the licensee confirmed positive NPSH margin after including the NPSHr uncertainty. The licensee also confirmed an acceptable time limit of operation in the zone of maximum erosion.

SSLB LOCA NPSH Analysis

The licensee stated that for all SSLB sizes analyzed, the peak suppression pool temperature for RSLB DBLOCA was bounding except for the most limiting SSLB of 0.01 ft^2, which gave a higher temperature response. During the first 10-minutes of the SSLB LOCA, the RHR and CS pumps are either not in operation or are operating at minimum flow. Therefore, the RHR and CS NPSH margins for all SSLBs, except for the long-term response of the 0.01 ft^2 break case, are bounded by the results of the RSLB DBLOCA analysis. The licensee made the following assumptions for the 0.01 ft^2 SSLB LOCA NPSH analysis: (1) assumed RHR and CS pump flows conservatively greater than assumed in the suppression pool temperature response safety analysis; (2) no changes to any of debris loading characteristics on the suction strainers, pipe frictional losses, and minimum suppression pool level result from the implementation of EPU; and (3) followed the guidance in RG 1.82 for determining the drawdown suppression pool water level.

Table 2.6.5.2-2 below shows the licensee's results extracted from PUSAR Table 2.6-5.

Table 2.6.5.2-2
SSLB LOCA NPSH Analysis Results

Analysis	Peak Suppression Pool Temperature (°F)	Pump	Uncertainty in NPSHr3 (%)	NPSH Margin [NPSHa - NPSHreff] (ft)	Operating Time in the Zone of Maximum Erosion (hours)
Single Unit	187	RHR	21	3.42	<4
		CS	21	0.34	<14
Long-Term Dual Unit Interaction	187.6	RHR	21	3.15	<4
		CS	21	0.08	<14

The NRC staff considers the SSLB LOCA NPSH evaluation acceptable because by using conservative inputs and assumptions and without the use of CAP, the licensee confirmed positive NPSH margin after including the NPSHr uncertainty. The licensee also confirmed an acceptable time limit of operation in the zone of maximum erosion.

Loss of RHR NSDC Event NPSH Analysis

For a loss of the RHR NSDC event NPSH analysis, the licensee analyzed two ASDC modes of achieving cold shutdown: (1) the CIC mode in which the RHR system performs suppression pool and reactor cooling; and (2) the SPC mode in which the RHR system performs SPC and the CS system performs reactor cooling. The licensee stated that analysis for ASDC in its CIC mode resulted in the highest suppression pool temperature response and therefore provides a more conservative input for the NPSH evaluation of the CS pump than does the SPC mode of ASDC operation. The NRC staff requested the licensee to justify reference to CS pumps in the CIC mode instead of the RHR pumps. In response to the RAI, the licensee, in Supplement 7 to the EPU LAR (Reference 8), stated that even though the CS pumps are not used in the CIC mode of ASDC, the intent is to conservatively evaluate the CS pumps when they are used in the SPC mode.

The licensee stated that during this event, while the reactor pressure is greater than the HPCI isolation pressure, the analysis conservatively assumes HPCI to provide the RPV makeup water using the suppression pool as the suction source. The use of the HPCI pump is limited to operation while the suppression pool temperature is less than 180 °F because of inadequate NPSHa above this temperature. The NRC staff requested the licensee to explain why the analysis assumption of using HPCI to provide RPV makeup is conservative for determining the peak suppression pool temperature. In response to the RAI, the licensee, in Supplement 7 to the EPU LAR (Reference 8), provided an evaluation of the suppression pool response during the two available reactor cooldown methods which are: (1) assuming a slow and controlled reactor cooldown rate using the HPCI system to provide makeup water; and alternately (2) assuming operator action initiating the ADS to depressurize the RPV so that the low pressure ECCS can provide core cooling. The licensee stated that the reactor blowdown by ADS causes an earlier transfer of the RPV liquid sensible energy to the suppression pool and a faster and earlier rise in the suppression pool temperature compared to the controlled cooldown method using HPCI. The faster and earlier increase in the suppression pool temperature-to-HPSW temperature difference controls the heat removal rate of the RHR HX. This would allow more energy to be removed from the suppression pool earlier in the event and therefore produce a lower peak suppression pool temperature than by the slow and controlled reactor depressurization and using HPCI system for reactor makeup.

The licensee made the following assumptions for the NPSH analysis: (1) assumed RHR and CS pump flows conservatively greater than assumed in the suppression pool temperature response safety analysis; (2) no suction strainer debris loading because the event does not include a pipe break; and (3) followed the guidance in RG 1.82 for determining the drawdown suppression pool water level. The licensee stated that the suppression pool temperature response analysis for the loss or RHR NSDC event with cold shutdown achieved by ASDC method is also applicable for a small liquid line break LOCA wherein SPC mode is used. The suppression pool peak temperature response for both of these events is bounded by the suppression pool temperature response for the limiting SSLB LOCA. Because of the higher suppression pool temperature in the SSLB LOCA analysis, the NPSH margin for this analysis is less than the NPSH margin for the small liquid line break. Table 2.6.5.2-3 below shows the licensee's results extracted from PUSAR Table 2.6-5.

Table 2.6.5.2-3
Loss of RHR NSDC Event NPSH Analysis Results

Analysis	Peak Suppression Pool Temperature (°F)	Pump	Uncertainty in NPSHr3 (%)	NPSH Margin [NPSHa - NPSHreff] (ft)	Operating Time in the Zone of Maximum Erosion (hours)
Single Unit	186	RHR	0	9.74	0
		CS	0	6.0	<11
Long-Term Dual Unit Interaction	186.7	RHR	0	9.43	<1
		CS	0	5.69	<11

The NRC staff considers the loss of RHR NSDC event NPSH evaluation acceptable because, by using conservative inputs and assumptions and without the use of CAP, the licensee confirmed positive NPSH margin. The licensee also confirmed an acceptable time limit of operation in the zone of maximum erosion.

SORV and RPV Isolation Event NPSH Analysis

For the SORV with RPV isolation event, the NPSH analysis assumed the RHR system operating in the SPC mode and the CS system providing RPV makeup water at low reactor pressure. The HPCI system, while drawing from the CST, provides RPV makeup water when the reactor pressure is greater than 150 psig. For the SORV event NPSH analysis, the RHR pumps are conservatively assumed to operate at 8732 gpm and the CS pumps operate at 3493 gpm. These flow rates are greater than the containment safety analysis flow rates. The analysis did not include suction strainer debris loading head loss. The NRC staff considers this assumption as realistic and acceptable. The calculated NPSH margin at the calculated maximum suppression pool temperature of 180 °F is 12.22 ft for the RHR pump and 8.48 ft for the CS pump. The operating time in the maximum operating zone (i.e., between NPSH ratio of 1.2 to 1.6) for the RHR pump is zero hours and for the CS pump is less than 6 hours.

The NRC staff considers the SORV and RPV isolation event NPSH evaluation acceptable because by using conservative assumptions and without the use of CAP, the licensee confirmed positive NPSH margin. The licensee also confirmed an acceptable time limit of operation in the zone of maximum erosion.

Appendix R Fire Event NPSH Analysis

For a postulated Appendix R Fire event, the licensee described four safe shutdown (SSD) methods designed to bring the plant to a cold shutdown condition. The licensee stated that these methods do not rely upon the RHR HX cross-tie modification. These methods are designated as A, B, C, and D. Their analyzed subset cases are described as follows, and as described in Supplement 7 to the EPU LAR (Reference 8):

<u>SSD Method A</u> uses the RCIC system, two SRVs, and one RHR subsystem (in the LPCI, pool cooling and ASDC modes) to achieve the cold shutdown. CS and HPCI are unavailable.

- Case A1: Without SORV during event
- Case A2: With one SORV during event

<u>SSD Method B</u> uses the HPCI system with suction from CST, two SRVs, and one RHR subsystem to achieve cold shutdown. CS and RCIC are unavailable.

- Case B1: Without SORV during event
- Case B2: With one SORV during event

<u>SSD Method C</u> uses manual control of three SRVs of the ADS for reactor depressurization, and either: (1) one CS pump and one RHR pump in SPC mode; or (2) one RHR pump in both LPCI mode and the SPC mode. HPCI and RCIC are unavailable.

- Case C1A: Without SORV during event. Core cooling provided by 1 CS pump
- Case C2A: With one SORV during event. Core cooling provide by 1 CS pump
- Case C1B: Without SORV during event. Core cooling provided by 1 RHR pump in the LPCI mode.
- Case C2B: With one SORV during event. Core cooling provided by 1 RHR pump in the LPCI mode.

<u>SSD Method D</u> uses same systems as method B except that operator control is taken outside of the main control room at designated alternative control stations.

- Case D1: Without SORV during event
- Case D2: With one SORV during event

The licensee also made the following conservative assumptions: (1) assumed RHR and CS pump flows conservatively greater than assumed in the suppression pool temperature response safety analysis; and (2) followed RG 1.82 for determining the suppression pool drawdown water level.

The licensee stated that the three cases A1, C1A, and C1B bound the results of the NPSH evaluation of the RHR and CS pumps. The licensee's determination is based on the parameters of peak suppression pool temperature, NPSH margin, and the time of operation in the maximum erosion zone.

The NRC staff requested in an RAI that the licensee provide the EPU evaluation of fire-induced multiple spurious operations (MSOs) and prevention of the loss of SSD and containment cooling capability during an Appendix R fire event. The licensee was also requested to address the PBAPS plant-specific scenarios listed in Table G-1 of Nuclear Energy Institute (NEI) guidance document NEI 00-01 (Reference 103). In response to the RAI, the licensee, in Supplement 10 to the EPU LAR (Reference 11), stated that in the current analysis, MSO scenarios were evaluated in accordance with NEI-00-01, Chapter 4 and Table G-1. The evaluation included PBAPS applicable plant-specific scenarios consistent with the guidance within NEI 00-01. The licensee stated that for EPU, the fire areas and SSD Methods A, B, C, and D remain unchanged from those considered in the current MSO evaluations. The licensee performed the evaluation of the current MSO scenarios for EPU to ensure that fire-induced MSOs will not result in loss of SSD and loss of containment cooling capability during an Appendix R Fire event. The licensee determined that the SSD capability during MSO scenarios will be maintained at EPU conditions because either the conclusions of the MSO scenario evaluation are not affected by the EPU, or the MSO scenarios affected by EPU have been identified and the necessary changes to ensure SSD capability is being implemented as part of the EPU. The licensee stated that if any additional EPU impacts of MSOs are determined, the licensee's configuration control process will ensure that the MSO coping capability will be maintained, including any new MSO scenarios introduced under the EPU conditions.

Table 2.6.5.2-4 below shows the licensee's results extracted from PUSAR Table 2.6-5.

Table 2.6.5.2-4
Appendix R Fire Event Analysis Results

Analysis Case	Peak Suppression Pool Temperature (°F)	Pump	Uncertainty in NPSHr3 (%)	NPSH Margin [NPSHa - NPSHreff] (ft)	Operating Time in the Zone of Maximum Erosion (hours)
A1	205.8	RHR	0	1.21	< 14
C1A	196.6	RHR	0	4.51	< 20
C1B	204.4	RHR	0	0.03	< 18
C1A	196.6	CS	0	0.77	< 40

The NRC staff considers the Appendix R fire event NPSH evaluation acceptable because by using conservative assumptions and without the use of CAP, the licensee confirmed positive NPSH margin. The licensee also confirmed an acceptable time limit of operation in the zone of maximum erosion.

SBO Event NPSH Analysis

During an SBO event, after the power is available, the NPSH analysis considers only one RHR pump drawing water from the suppression pool. The HPCI system, while taking suction from the CST, is credited for 30 minutes supplying makeup water to the RPV. The licensee conservatively assumed RHR pump flow to be greater than the flow assumed in the suppression pool temperature response analysis. The analysis did not include debris loading in the suction strainer head loss, which is realistic and acceptable for an SBO event. The suppression pool level assumed is increased from its nominal level because of use of either RCIC or HPCI for RPV makeup with suction from the CST. The NPSH margin at the calculated maximum suppression pool temperature of 198 °F is 5.3 ft. The operating time in the maximum operating zone (i.e., between NPSH ratio of 1.2 to 1.6) is less than 5 hours.

The NRC staff considers the SBO event NPSH evaluation acceptable because by using conservative assumptions and without the use of CAP, the licensee confirmed positive NPSH margin. The licensee also confirmed an acceptable time limit of operation in the zone of maximum erosion.

ATWS Event NPSH Analysis

The ATWS event NPSH analysis considers the RHR pumps operating with suction from the suppression pool, while the HPCI system, taking suction from the CST, supplies makeup water to the RPV. The CS pumps are not credited for the ATWS event. The licensee made conservative assumptions which are: (1) assumed RHR pump flow conservatively greater than assumed in the suppression pool temperature response safety analysis; and (2) included debris loading in the suction strainer head loss. The suppression pool level assumed is increased from its nominal level because of the use of either RCIC or HPCI for RPV makeup with suction from the CST. The NPSH margin at the maximum suppression pool temperature of 168.3 °F is 15.54 ft. The operating time in the maximum erosion zone (i.e., between NPSH ratio of 1.2 to 1.6) is zero hours.

The NRC staff considers the ATWS event NPSH evaluation acceptable because by using conservative assumptions and without the use of CAP, the licensee confirmed positive NPSH margin. The licensee analysis showed that the RHR pump would not operate in the maximum erosion zone.

Summary

The following is a summary of the results, derived from the above technical evaluation, related to the acceptance criteria given in the NRC regulatory requirements for the primary containment heat removal system under EPU conditions:

- The containment heat removal system, as modified, will prevent exceeding containment design pressure under accident conditions.

Conclusion

The NRC staff has reviewed the containment heat removal systems' assessment provided by the licensee and concludes that the licensee has adequately addressed the effects of the proposed EPU. The NRC staff finds that the systems will continue to meet draft GDCs 41 and 52 with respect to rapidly reducing the containment pressure and temperature following a LOCA and maintaining them at acceptably low levels. Therefore, the NRC staff finds the proposed EPU acceptable with respect to containment heat removal systems.

2.6.6 Secondary Containment Functional Design

Regulatory Evaluation

The secondary containment structure and supporting systems of dual containment plants are provided to collect and process radioactive material that may leak from the primary containment following an accident. The supporting systems maintain a negative pressure within the secondary containment and process this leakage. The NRC staff's review covered: (1) analyses of the pressure and temperature response of the secondary containment following accidents within the primary and secondary containments; (2) analyses of the effects of openings in the secondary containment on the capability of the depressurization and filtration system to establish a negative pressure in a prescribed time; (3) analyses of any primary containment leakage paths that bypass the secondary containment; (4) analyses of the pressure response of the secondary containment resulting from inadvertent depressurization of the primary containment when there is vacuum relief from the secondary containment; and (5) the acceptability of the mass and energy release data used in the analysis. The NRC staff's review primarily focused on the effects that the proposed EPU may have on the pressure and temperature response and drawdown time of the secondary containment, and the impact this may have on offsite dose. The NRC's acceptance criteria for secondary containment functional design are based on: (1) draft GDC-40 and 42, insofar as they require that protection be provided for ESFs against the dynamic effects that might result from plant equipment failures, as well as the effects of a LOCA; and (2) draft GDC-10, insofar as it requires that reactor containment be designed to sustain the initial effects of gross equipment failures, such as a large coolant boundary break, without loss of required integrity and, together with other ESFs as may be necessary, to retain functional capability for as long as the situation requires. Specific review criteria are contained in SRP Section 6.2.3.

Technical Evaluation

The secondary containment is maintained at a negative pressure during the abnormal events and accident conditions by the standby gas treatment system (SGTS). The SGTS also provides an elevated release path, minimizes ground level release, and limits the off-site dose. An increase in RTP increases the heat load on the secondary containment and may affect the drawdown time of the secondary containment. The drawdown time is the time period following the start of the accident or the abnormal event during which loss of offsite power causes loss of secondary containment vacuum (relative to atmospheric pressure), which is assumed to result in releases from the primary containment directly to the environment without filtering.

The licensee stated that the current design flow capacity of the SGTS maintains the secondary containment at the required negative pressure to minimize the potential for ex-filtration of air from the reactor building during an accident. [[

]]

The licensee stated that the secondary containment structure, openings, and pathways, and drawdown time are unaffected by EPU. Because the maximum dome pressure is also not changed for EPU, there is no effect to the ability of secondary containment to contain mass and energy (M&E) released to it, and there is no increase in M&E released to secondary containment for EPU. The NRC staff requested the licensee in an RAI to: (1) explain what is meant by the ability of secondary containment to contain M&E released to it; (2) which break M&E released in the secondary containment is being referred to in the above statement; and (3) explain how the reactor dome pressure affects the ability of the secondary containment M&E released to the secondary containment. In response to the RAI, the licensee, in Supplement 7 to the EPU LAR (Reference 8), stated that the statement refers to a LOCA inside primary containment and concerns the ability of the secondary containment and the SGTS to maintain post-LOCA effluent volume within the design and regulatory limits. The design flow capacity of the SGTS is not affected because the specified primary and secondary containment leak rates are not changed by the constant pressure power uprate. Therefore the M&E released from the primary containment to the secondary containment is unchanged under EPU conditions. The licensee has also shown, through the accident analysis for the EPU conditions, that the maximum containment pressure remains within the current TS limit, which ensures that the primary and secondary containment leakage will not be significantly different from the current configuration.

Summary

The following is a summary of the results, derived from the above technical evaluation, related to the acceptance criteria given in the NRC regulatory requirements for the secondary containment functional design under EPU conditions:

- ESFs SSCs inside the secondary containment are protected from the dynamic effects resulting from plant equipment failures, as well as the effects of a LOCA.

- The current secondary containment required integrity and ESF SSCs functional capability is maintained during gross equipment failures, such as a large reactor coolant pressure boundary break, for as long as the conditions require.

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 M&E that would result from the proposed EPU and further concludes that the secondary containment and associated systems will continue to provide an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment following implementation of the proposed EPU. Based on this, the NRC staff also concludes that the secondary containment and associated systems will continue to meet the requirements of draft GDCs 10, 40 and 42. Therefore, the NRC staff finds the proposed EPU acceptable with respect to secondary containment functional design.

2.6.7 Additional Review Areas (Containment Review Considerations)

2.6.7.1 Containment Isolation

Regulatory Evaluation

The NRC staff acceptance criteria for the containment isolation are based on draft GDC-49, insofar as it requires that the containment be designed so that the containment structure can accommodate, without exceeding the design leakage rate, the pressures and temperatures resulting from the largest credible energy release following a LOCA.

Technical Evaluation

The licensee reviewed the containment isolation portions of the systems penetrating the primary containment and determined that EPU does not affect the containment isolation devices and the capability to isolate the primary containment during normal operation or accident conditions.

The licensee discussed the effects of EPU on its motor operated containment isolation valve programs related to Generic Letter (GL) 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance" (Reference 44), GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves" (Reference 46), and GL 96-05, "Periodic Verification of

Design-Basis Capability of Safety-Related Motor-Operated Valves" (Reference 45), as discussed in SE Section 2.2.4.

Conclusion

The NRC staff finds that the EPU does not adversely affect system designs for containment isolation capabilities, which continue to meet the requirements of draft GDC-49. Therefore, the staff finds the proposed EPU acceptable with respect to containment isolation.

2.6.7.2 Generic Letter 89-13

Regulatory Evaluation

NRC GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment" (Reference 104), requested licensees to establish a routine inspection and maintenance program to ensure that corrosion, erosion, protective coating failure, silting, and biofouling/tube plugging cannot degrade the performance of the safety-related systems supplied by service water. These issues relate to the evaluation of safety-related HXs using service water and whether they have the potential for fouling, thereby causing degradation in performance, and the mandate that there exist a permanent plant test and inspection program to accomplish and maintain this evaluation.

Technical Evaluation

The NRC staff requested in a RAI that the licensee describe the GL 89-13 testing for the RHR HXs and discuss the accuracy of the testing with respect to design conditions. Since the EPU is implementing a lower heat transfer margin for the RHR HXs, the licensee was requested to justify reliance on GL 89-13 testing as a means of assuring that the required heat transfer capability of the RHR HXs is maintained. In response to the RAI, the licensee stated, in Supplement 7 to the EPU LAR (Reference 8) that:

> The GL 89-13 testing of the RHR HXs involves installation of temporary temperature and permanent flow instrumentation to collect data necessary to compute the HX shell side and tube side heat transfer rates. With respect to the design conditions (acceptance criteria) the implementing test procedures include steps to compare the process and tube side heat transfer rates and to statistically evaluate test data such that the results conservatively account for the uncertainties of each test. Thus, the accuracy of each test, which can vary from one test to another, is reflected in the test result which is compared to the acceptance criteria.
>
> ...the EPU acceptance criteria basis K-value is 305 BTU/sec-°F. Historical test data shows that the maximum RHR HX fouling from recent tests (2008-2012) resulted in a minimum K-value of approximately 330 BTU/sec-°F (including test measurement uncertainty,... This margin remains sufficiently large such that the EPU acceptance criterion is not expected to be challenged during future plant operation. Additionally, current HX maintenance (cleaning) frequencies are not expected to be changed or adversely impacted. The PBAPS GL 89-13 testing

program and implementing procedures will ensure that the required heat transfer capability will be maintained.

The NRC staff finds the licensee's response acceptable because there is sufficient margin between the historical test data, including measurement uncertainty, and the acceptance criteria for the RHR HX K-value, to ensure that the heat transfer capability under EPU conditions will be maintained.

Conclusion

The NRC staff considers the licensee's evaluation of the RHR HX under EPU conditions, with respect to GL 89-13, is acceptable.

2.6.7.3 Generic Letter 89-16

Regulatory Evaluation

Generic Letter 89-16, "Installation of a Hardened Wetwell Vent" (Reference 105), discusses 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's BWR Mark I Containment Performance Improvement Program.

Technical Evaluation

The licensee stated in PUSAR Section 2.6.1.4 that currently both PBAPS units have hardened vents to relieve wetwell gas space pressure to the atmosphere. Using BWROG design criteria, the licensee had sized the vent to exhaust sufficient steam to prevent the containment pressure from exceeding the primary containment design pressure (60 psig) with a constant heat input equal to 1% of 3458 MWt. The licensee stated that because of the conservatism in its design, the current vent will provide adequate pressure protection with a constant heat input equal to 1% of the EPU RTP of 3951 MWt.

Conclusion

The NRC staff considers the licensee's evaluation of the hardened wetwell vent with respect to GL 89-16 requirements under EPU conditions acceptable. The NRC issued Order EA-12-109 on June 6, 2013 (ADAMS Accession No. ML13143A321), requiring BWR Mark I and Mark II containments to install a severe accident capable reliable hardened vent from the wetwell and the drywell. The licensees also have the option of implementing alternate venting strategies in lieu of a drywell vent. As a result, the licensee is expected to either modify the existing vent or install a new vent from the wetwell to comply with the order. The order requires that the severe accident capable reliable hardened vent be operational no later than startup from the second refueling outage that begins after June 30, 2014, or June 30, 2018, whichever comes first.

2.6.7.4 Generic Letter 96-06

Regulatory Evaluation

NRC GL 96-06, "Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions" (Reference 106), identifies the following potential problems with equipment operability and containment integrity during DBA conditions: (1) cooling water systems serving the containment air coolers may be exposed to water hammer during postulated accident conditions; (2) cooling water systems serving the containment air coolers may experience two-phase flow conditions during postulated accident conditions; and (3) thermally induced overpressurization of isolated water-filled piping sections in containment could jeopardize the ability of accident-mitigating systems to perform their safety functions and could also lead to a breach of containment integrity via bypass leakage. GL 96-06 questioned whether the higher heat loads at accident conditions could potentially cause steam bubbles, water hammer, and two-phase flow due to the higher outlet temperatures from cooled components, particularly the containment fan coolers.

Technical Evaluation

The licensee stated in PUSAR Section 2.6.1.5 that its current response to GL 96-06 is not affected for EPU conditions because: (1) it credits existence of sufficient pressure in the cooling water lines that prevents formation of steam and avoids water hammer under post-accident conditions; and (2) the relief valve installed capacity to prevent overpressurization of lines penetrating primary containment is much greater than the required capacity, and its sizing was based on a drywell temperature that is the same as expected during DBLOCA conditions so that a slight increase in the drywell temperature at EPU condition has no impact. The NRC staff requested in a RAI that the licensee describe the water hammer that could potentially occur in the cooling water lines and its method of prevention. In response to the RAI, the licensee, in Supplement 10 to the EPU LAR (Reference 11), stated that water hammer can potentially occur in the drywell chilled water system piping inside containment when the post-accident containment conditions result in heating of the water in the containment air coolers to saturation temperature prior to the re-establishment of water flow. The licensee's EPU evaluation determined that the water in the containment air coolers will not reach saturation temperature in the short time before the fluid pressure is increased and flow re-established. The NRC staff agrees with licensee's evaluation.

Conclusion

The NRC staff finds the licensee has re-evaluated the issues associated with GL-96-06 and has taken actions to address the concerns therein for applicability to EPU conditions to ensure that they remain addressed for EPU conditions. Therefore, the NRC staff finds the licensee's evaluation of GL 96-06 for EPU conditions to be acceptable.

2.7 Habitability, Filtration, and Ventilation

2.7.1 Control Room Habitability System

Regulatory Evaluation

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

Technical Evaluation

The main control room habitability system maintains the control room habitable during normal plant operation and during design-basis accident (DBA) conditions and during and anticipated operational occurrences (AOOs). The control room habitability system mainly consists of a control room air-conditioning system of which a fresh air supply fan and control room emergency ventilation (CREV) system are sub-parts. If a high activity or loss of flow is detected in the normal fresh air intake, the fresh air supply fan and the air conditioning system shuts down, and one of the two high efficiency charcoal filter train starts automatically. The CREV system filters the fresh air intake to prevent iodine and particulate contamination of the main control room air and pressurize the main control room envelope. The licensee stated that the radiological impact of EPU on the emergency ventilation system is an increase in the particulates, including particulate iodine, released during an accident. The licensee has already implemented the alternative source term (AST) methodology for PBAPS for which the radiological analysis for DBAs was performed at 102% of the EPU power level for all the DBAs currently documented in Chapter 14 of the PBAPS UFSAR. The licensee stated that the AST analysis control room dose limits, in all cases, were within regulatory limits. The licensee also stated that the quantities and locations of gases and hazardous chemicals that could affect control room habitability are unaffected by EPU.

Conclusion

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

2.7.2 Engineered Safety Feature 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., standby gas treatment systems 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 proposed EPU on system functional design, environmental design, and provisions to preclude temperatures in the adsorber section from exceeding design limits. The NRC's acceptance criteria for ESF atmosphere cleanup systems are based on: (1) final 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) draft GDC-69, insofar as it requires that systems that may contain radioactivity be designed to assure adequate safety under normal and postulated accident conditions; and (3) final 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.

Technical Evaluation

Each of PBAPS units has two ESF atmosphere cleanup systems: (1) the CREV system; and (2) the standby gas treatment system (SGTS). Section 2.7.1 of this SE provides the evaluation of the CREV system. The SGTS maintains the secondary containment at a negative pressure during DBA conditions and AOOs. It provides an elevated release path for the exhaust air for removal of fission products potentially present and limits the offsite dose following DBA or AOOs. The evaluation of the flow performance of SGTS under EPU conditions is provided in SE Section 2.6.6. The evaluation of the SGTS with respect to fission product control is provided in SE Section 2.5.2.1. The evaluation of control room doses is provided in SE Section 2.9.2.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ESF atmosphere cleanup systems. The NRC staff concludes that the licensee has adequately accounted for the increase of fission products and changes in expected environmental conditions that would result from the proposed EPU, and the NRC staff further concludes that the ESF atmosphere cleanup systems will continue to provide adequate fission product removal in post-accident environments following implementation of the proposed EPU.

Based on this, the NRC staff concludes that the ESF atmosphere cleanup systems will continue to meet the requirements of final GDCs 19 and 64 and draft GDC-69. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the ESF atmosphere cleanup systems.

2.7.3 Control Room Area Heating, Ventilation and Air Conditioning System

Regulatory Evaluation

The function of the control room area heating, ventilation and air conditioning (HVAC) system 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 control room area HVAC system focused on the effects that the proposed EPU will have on the functional performance of safety-related portions of the system. The review included the effects of radiation, combustion, and other toxic products; and the expected environmental conditions in areas served by the system. The NRC's acceptance criteria for the control room area HVAC system are based on: (1) final 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) final 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) final GDC-60 , insofar as it requires that the plant design include means to control the release of radioactive effluents. Specific review criteria are contained in SRP Section 9.4.1.

Technical Evaluation

The control room area HVAC system maintains temperature and humidity conditions suitable for personnel comfort and for equipment reliable operation inside the control room envelope. The system also maintains the control room envelope at positive pressure preventing outside air infiltration during accident or emergency operating conditions. The licensee stated that under EPU conditions, the control room heat loads are not affected by the slightly higher process temperatures, thus they are not power dependent. The licensee also stated that electrical or electronic equipment is not being added inside the control room envelope except for new control valve hand switches and instrumentation supporting the modifications for increasing the suppression pool cooling capability described in Attachment 9 to the EPU LAR. The licensee stated that the effect of these devices on the change in heat load and temperature is considered negligible. The change of conductance of heat through the building structure to the control room envelope is expected to be negligible. The NRC staff agrees that operating under EPU conditions does not affect the control room area HVAC system operation during normal and AOOs to perform its required functions.

The evaluation of control of the airborne radioactive material in the control room envelope during accidents and emergency operations under EPU conditions is evaluated in SE Section 2.7.1. The licensee also stated that there is no increase in toxic gas releases under EPU conditions.

The licensee stated that the proposed installation of a recirculation pump adjustable speed drive (ASD) mentioned in Attachment 9 to the EPU LAR will add some electrical or electronic equipment in the cable spreading room, which is a part of the control room envelope. The licensee stated that while no adverse impact is anticipated based on preliminary data, a final evaluation of any possible impact on the control room area HVAC system will be determined as a part of standard design process. As discussed in Supplement 7 to the EPU LAR (Reference 8), the licensee stated that the EPU does not rely on this modification, nor is approval of this modification requested. The licensee also stated that this modification is planned in the year 2015 for Unit 3, and 2016 for Unit 2, and design data is not currently available. The modification will be controlled by the licensee's configuration change control and will be implemented under the 10 CFR 50.59 process. The NRC staff therefore concludes that the proposed EPU does not affect the control room area HVAC system parameters.

Conclusion

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

2.7.4 Spent Fuel Pool Area Ventilation System

As discussed in Section 2.7.4 of the PUSAR, the PBAPS design does not contain a separate spent fuel pool area ventilation system. Ventilation in this area is provided by the reactor building HVAC system under normal conditions. The SGTS provides ventilation in this area during accident conditions. The reactor building HVAC system is evaluated in SE Section 2.7.5. The SGTS is evaluated in SE Sections 2.5.2.1 and 2.6.6.

2.7.5 Reactor, Turbine, Drywell and Radwaste Area Ventilation Systems

Regulatory Evaluation

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

Technical Evaluation

The power dependent HVAC systems are reactor building, turbine building, drywell, and the radwaste building HVAC systems. The airborne radioactive particulate concentration in the reactor building is controlled by the reactor building HVAC system during normal operation. During accident conditions and AOOs, the concentration of airborne radioactive material effluent from the reactor building is controlled by the SGTS, which is evaluated in Sections 2.5.2.1 and 2.6.6 of this SE.

The licensee stated that the main steam tunnel (MST) temperature increase will be less than 0.5 °F at EPU conditions. In an RAI, the NRC staff requested the licensee to describe the method of evaluation of the increase in the MST temperature under EPU conditions. In response to the RAI, the licensee stated in Supplement 7 to the EPU LAR (Reference 8), that the only EPU heat load increase affecting the MST is due to the FW temperature increase, which is obtained from the turbine cycle heat balances. The licensee used the same methodology to predict the increase in MST area temperature under EPU conditions as used in the current design basis calculations. Since the piping heat loads are proportional to the temperature difference between the hot pipes and the MST area, the heat load from the FW piping is increased proportionally to the EPU FW temperature conditions. The licensee estimated the MST area temperature change based on the increase in heat load due to the FW temperature change.

The NRC staff requested, in an RAI, that the licensee provide a discussion of the increased HVAC heat load due to the increase in the power dependent spent fuel pool (SFP) cooling system heat load, and also provide the impact of the increased fuel pool heat load on the reactor building heat load and its HVAC design capacity. In response to Supplement 7 to the EPU LAR (Reference 8), the licensee stated that EPU does not add heat load on the reactor building HVAC system because the SFP temperature is maintained within design limits by the fuel pool cooling and cleanup system (FPCCS) and through existing administrative and procedural limitations. There is a slight increase in the SFP temperature under EPU conditions, which has no effect on the reactor building HVAC system. Therefore, the reactor building HVAC system current design capacity is adequate.

In Attachment 9 to the EPU LAR, the licensee stated that all condensate pumps and motors will be upgraded. The NRC staff requested the licensee, in an RAI, to provide the final design increase in heat load due to the upgrades and its impact on the turbine building HVAC system. In response to the RAI, the licensee stated, in Supplement 7 to the EPU LAR (Reference 8), that the design changes are not presently finalized. However, by an initial evaluation, the licensee has estimated an 11% increase in the condensate pump motor power resulting in a proportional increase in the room heat load. The estimated room temperature increase is less than 5 °F due to the increased heat load, which has been evaluated to be acceptable. The licensee stated that the impact of the heat load changes will be analyzed and documented during the implementation of the modification through the 10 CFR 50.59 process.

The licensee stated that the proposed installation of the ASD will result in a reduced heat load in the motor-generator sets room HVAC system and may increase heat load on the turbine building HVAC system. However, the increased heat load with ASD does not significantly affect the temperature increase in the turbine building under EPU conditions. The licensee's calculated maximum temperature increase is within the daily anticipated temperature variation. Therefore, the staff considers that the licensee has adequately considered the impact of EPU on the turbine building HVAC system.

The licensee stated that the increase in drywell heat load are not significant and are within existing system margin.

Based on the above, the NRC staff finds that the licensee has adequately addressed the impacts of the proposed EPU with respect to the reactor building, turbine building, drywell and radwaste building HVAC systems.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the reactor building, turbine building, drywell and radwaste building HVAC systems. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the capability of these systems to maintain ventilation in these areas, 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 reactor building, turbine building, drywell and radwaste building HVAC systems will continue to meet the requirements of final GDC-60. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the reactor building, turbine building, drywell and radwaste building HVAC systems.

2.7.6 Engineered Safety Feature Heating, Ventilation and Air Conditioning Systems

Regulatory Evaluation

The function of the ESF HVAC system is to provide a suitable and controlled environment for ESF components following certain anticipated transients and DBAs. The NRC staff's review for the ESF HVAC systems focused on the effects of the proposed EPU on the functional performance of the safety-related portions of the system. The NRC staff's review also covered: (1) the ability of the ESF equipment in the areas being serviced by the ventilation system to function under degraded system performance; (2) the capability of the systems 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 systems to control airborne particulate material (dust) accumulation. The NRC's acceptance criteria for the ESF HVAC systems are based on: (1) draft GDC-40 and 42, insofar as they require that protection be provided for ESFs against the dynamic effects that might result from plant equipment failures, as well as the effects of a LOCA; (2) final GDC-17, insofar as it requires onsite and offsite electric power systems be provided to permit functioning of SSCs important to safety; and (3) final GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents. Specific review criteria are contained in SRP Section 9.4.5.

Technical Evaluation

The ESF HVAC systems control the environmental conditions in the emergency switchgear rooms, battery rooms, standby diesel generator rooms, the emergency service water (ESW) and high-pressure service water (HPSW) compartments, and the emergency core cooling system (ECCS) pump rooms during normal operation, during AOOs, and during accident conditions. These systems do not function to control the concentration of airborne radioactive material in these areas. Sections 2.5.2.1 and 2.6.6 of this SE provide the evaluation of the SGTS, which controls the concentration of airborne radioactive material in the secondary containment during normal operation, during AOOs, and after postulated accidents. The licensee stated that the EPU environmental conditions in these areas served by the applicable HVAC systems are unaffected because the reactor building and the suppression pool process fluid temperatures remain bounded by their current values. The licensee also stated that the EPU does not change the design heat loads in these rooms and there are no major equipment modifications in the emergency switchgear and battery rooms, and the ESW and HPSW compartments.

The licensee stated that there is a small increase in the EPU heat loads in the emergency diesel generators (EDG) rooms, but are bounded by the design heat load with enough margins available to maintain the current design temperatures. The NRC staff requested the licensee, in an RAI, to describe the changes due to EPU affecting the EDG building heat load during normal and accident conditions. In response to the RAI, the licensee stated, in Supplement 7 to the EPU LAR (Reference 8), that during normal conditions, EPU will have no effect on the EDG building heat loads because the EDGs do not operate during normal plant conditions except during EDG surveillance testing, which is not changed with EPU. During accident conditions, while the EDGs are in operation, the combined EDG electrical operating load will increase with EPU. The increase is due to the additional HPSW pump motor loads required to support the residual heat removal (RHR) system heat exchanger cross-tie design for increased containment cooling. However, there is also a reduction in loading resulting from reduced RHR system flow to support containment accident pressure (CAP) credit elimination. The net increase in EDG electrical operating load causes an increase in the heat loads in the EDG rooms. However, the increase is less than the design basis heat load used for the EDG building HVAC system design. The specific HVAC design basis heat load is based on each EDG operating between 3200 and 3300 kilowatt (kW) electrical load, which bounds the 3000 kW EDG electrical operating load for any EDG under EPU conditions.

The NRC staff finds that the licensee has adequately addressed the impacts of the proposed EPU with respect to the impacts on the ESF HVAC systems.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ESF HVAC systems. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the ability of the systems to provide a suitable and controlled environment for ESF components. The NRC staff further concludes that the ESF HVAC systems will continue to assure a suitable environment for the ESF components following implementation of the proposed EPU. The NRC staff also concludes that the ESF HVAC systems will continue to suitably control the release of gaseous radioactive effluents to the environment following implementation of the proposed EPU. Based on this, the NRC staff concludes that the ESF HVAC systems will continue to meet the requirements of final GDCs 17 and 60, and draft GDCs 40 and 42. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the ESF HVAC systems.

2.8 Reactor Systems

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) final 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; and (3) draft GDCs 37, 41, and 44, insofar as they require that a system to provide abundant emergency core cooling be provided to prevent fuel damage following a LOCA. Specific review criteria are contained in SRP Section 4.2 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

The licensee provided information regarding the fuel system design in Section 2.8.1 of the PUSAR, Appendix A to the PUSAR, and in Supplement 6 to the EPU LAR (Reference 7). PBAPS, Units 2 and 3, began transitioning from GE14 to GNF2 fuel in Cycle 19 and the transition is to be completed prior to Cycle 21 (the first EPU cycle) for both units. The reactor core for EPU operation is planned to contain exclusively GNF2 fuel. However, based on the NRC SE for GE-Hitachi Nuclear Energy Americas LLC (GEH) licensing topical report (LTR) NEDC-33173P-A (Reference 69, referred to as the interim methods licensing topical report (IMLTR)), a mixed core is defined as a "mixed fuel vendor core" or a core with "fuel type characteristics not covered in this [i.e., the IMLTR] review." Therefore, a core consisting of co-resident GE14 and GNF2 fuel would not be considered a mixed core. PBAPS plans to exclusively use GEH/GNF fuel types through the EPU implementation, ensuring that no cores are considered mixed. The fuel design for EPU is evaluated on a plant-specific basis in accordance with ELTR1 (Reference 21).

GNF2 fuel is currently resident in the PBAPS cores. [[

]] The current fuel design limits for the resident GNF2 fuel have been established in accordance with the General Electric Standard Application for Reactor Fuel (GESTAR II) (Reference 68).

The NRC staff has reviewed the licensee's submittal and found that the fuel system design analysis has been performed in accordance with the assumptions and scope outlined in ELTR1. The EPU analyses are consistent with the PBAPS licensing basis and use NRC-approved methodology and codes.

The NRC staff has reviewed the application of the GESTAR II process described in the PUSAR and the GNF2 generic compliance document, NEDC-33270P, Revision 5 (Reference 71). GESTAR II provides the licensing criteria for GE fuel design thermal-mechanical analyses. The GNF2 generic compliance report and the plant-specific analyses presented in the PUSAR for the equilibrium EPU core use "The PRIME Model for Analysis of Fuel Rod Thermal-Mechanical (T-M) Performance" (PRIME) (Reference 72), which is an NRC approved, modern fuel performance code. The PRIME code properly accounts for fuel thermal conductivity degradation with fuel burnup, which has been a major issue during recent pressurized-water reactor EPU reviews.

The NRC staff has performed significant confirmatory calculations, using the NRC audit code FRAPCON-3, for the GNF2 GESTAR II compliance report, as well as for the PRIME code along with its licensing methodology. In the initial audit on the GNF2 GESTAR II compliance report, the staff had a significant number of findings that led the NRC to initially preclude batch application of GNF2 fuel. These findings were later addressed by GEH in Amendment 32 to GESTAR II, which was reviewed and approved in 2009. This approval contained three limitations and conditions as follows:

1. The GNF2 fuel assembly design is approved for [[ ]]

2. The NRC staff review and approval is limited to the zirconium barrier GNF2 fuel rod design.

3 The application of GESTAR II to the GNF2 fuel assembly design is approved for [[ ]]

The first and third limitations have been addressed by GEH in Amendment 33 to GESTAR II. The NRC staff SE for Amendment 33 to GESTAR II (Reference 73) states that licensees referencing GESTAR II no longer need to comply with limitations one and three above and the approved burnup limit for the GNF2 fuel assembly is [[ ]] The staff also performed additional FRAPCON confirmatory calculations during the review of Amendment 33 of the GNF2 PRIME based thermal-mechanical operating limit (TMOL) and thermal over power (TOP)/mechanical over power (MOP) limits documented in the GNF2 Compliance Report. These limits have not changed and will continue to be used at PBAPS.

PBAPS, Units 2 and 3, will continue to use the NRC-approved process, GESTAR II, for the GNF2 fuel thermal-mechanical analyses utilizing the PRIME methods. The GESTAR II process is approved to demonstrate compliance with the fuel design criteria contained in SRP Section 4.2. Therefore, the NRC staff finds the EPU acceptable with respect to the fuel design limits.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the fuel system design of the fuel assemblies, control systems, and reactor core. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the fuel system and demonstrated that: (1) the fuel system will not be damaged as a result of normal operation and AOOs; (2) the fuel system damage will never be so severe as to prevent control rod insertion when it is required; (3) the number of fuel rod failures will not be underestimated for postulated accidents; and (4) coolability will always be maintained. Based on this, the NRC staff concludes that the fuel system and associated analyses will continue to meet the requirements of 10 CFR 50.46, final GDC-10 and draft GDCs 37, 41 and 44 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the fuel system design.

2.8.2 Nuclear Design

Regulatory Evaluation

The NRC staff reviewed the nuclear design of the fuel assemblies, control systems, and reactor core to ensure that fuel design limits will not be exceeded during normal operation and 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, burnup, and vessel irradiation. The NRC's acceptance criteria are based on: (1) final 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) draft GDC-8, insofar as it requires that the reactor core be designed so that the overall power coefficient in the power operating range shall not be positive; (3) final 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) draft GDCs 12 and 13, insofar as they require that instrumentation and controls be provided, as required, to monitor and maintain variables within prescribed operating ranges through the core life; (5) draft GDCs 14 and 15, insofar as they require that the protection system be designed to initiate the reactivity control systems automatically to prevent or suppress conditions that could result in exceeding acceptable fuel damage limits and to initiate operation of ESFs under accident situations; (6) draft GDC-31, insofar as it requires that the reactivity control systems be capable of sustaining any single malfunction without causing a reactivity transient, which could result in exceeding acceptable fuel damage limits; (7) draft GDCs 27 and 28, insofar as they require that at least two independent reactivity control systems be provided, with both systems capable of making and holding the core subcritical from any hot standby or hot operating condition sufficiently fast to prevent exceeding acceptable fuel damage limits; (8) draft GDCs 29 and 30, insofar as they require that at least one of the reactivity control systems be capable of making and holding the core subcritical under any condition sufficiently fast to prevent exceeding acceptable fuel damage limits; and (9) draft GDC-32, insofar as it requires that limits, which include considerable margin, be placed on the maximum reactivity worth of control rods or elements and on rates at which reactivity can be increased to ensure that the potential effects of a sudden or large change of reactivity cannot: (a) rupture the reactor coolant pressure boundary; or (b) disrupt the core, its support structures, or other vessel internals sufficiently to impair the effectiveness of emergency core cooling. Specific review criteria are contained in SRP Section 4.3 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

The licensee provided information regarding the nuclear design in Section 2.8.2 of the PUSAR, Appendix A to the PUSAR, and in Supplement 6 to the EPU LAR (Reference 7). The NRC staff's technical evaluation of this information is provided below.

Core Operation - Background Information

EPU requires additional energy output from the core and this requires an increase in the energy loaded in to the core each cycle. Core reload design for the EPU core must consider several factors, such as fuel design limits, establishing safe operating limits, corporate generation goals and optimization of the use of energy in a core. Given the selection of fuel type as GNF2, [[

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EPU increases the average power density proportional to the power increase, which has some effects on operating flexibility, reactivity characteristics, and energy requirements. The additional energy requirement for EPU are met by increase in fuel bundle enrichment, an increase in the reload fuel batch size, and/or change in fuel loading pattern to maintain the desired plant operating cycle length.

Core Design

The cycle-specific core design for EPU at PBAPS involves a two-fold approach: [[

]] These NRC-approved methods assure that the requisite core design limits are met during the design process.

Fuel bundles are designed to ensure that:

- the fuel bundles are not damaged during normal steady-state operation and AOOs;
- any damage to the fuel bundles will not be so severe as to prevent control rod insertion when required;
- the number of fuel rod failures during accidents is not underestimated; and
- the coolability of the core is always maintained.

The maximum allowable peak bundle power is not increased by power uprate. However, the additional energy requirement for EPU are met by an increase in 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. The power distribution in the core is changed to achieve increased core power, while limiting the minimum critical power ratio (MCPR), linear heat generation rate (LHGR), and maximum average planar linear heat generation rate (MAPLHGR) in any individual fuel bundle to be within its allowable limits, as defined in the core operating limits report (COLR).

The reactor core design power distribution and the resultant thermal operating state at design conditions allow margins for the combined effects of the fuel heat flux and temperature, local power density distributions, control rod pattern, and reactor power level adjustments during plant operation. The licensee stated in PUSAR Section 2.8.2.1.1 that detailed fuel cycle calculations of a representative equilibrium core design for PBAPS demonstrate the feasibility of EPU rated thermal power (RTP) operation while maintaining fuel design safety limits. The licensee also stated that thermal-hydraulic design analyses have shown that there is an acceptably low probability of boiling transition-induced cladding failure even for the most severe postulated operational transients. Key inputs for the PBAPS EPU equilibrium core are listed in Table 7-1 in Attachment 1 to Supplement 6 to the EPU LAR (Reference 7). Table 7-2 in Attachment 1 to Supplement 6 lists inputs, reload batch size, bundle average enrichment, bundle weight of Uranium and Uranium Dioxide for the PBAPS EPU representative equilibrium core design analysis. Results for the equilibrium core analysis are presented in Tables 7-3 through 7-6 in Attachment 1 to Supplement 6. The NRC staff reviewed the results and determined that all thermal, reactivity, and bundle, pellet and peak nodal exposure limits are met.

The licensee stated that EPU may result in a small change in fuel burnup, the amount of fuel to be used, and isotopic concentrations of the radionuclides in the irradiated fuel relative to the original level of burnup. NRC-approved limits for burnup on the GNF2 fuel design will not be exceeded (Reference 68). The predicted PBAPS, Unit 2, end-of-cycle 18 peak bundle average discharge burnup and EPU peak bundle average discharge exposure are both less than the GNF2 fuel bundle average discharge exposure limit and therefore in compliance with fuel-dependent limitations on discharge burnup. The predicted PBAPS, Unit 2, Cycle 19 weighted fresh bundle enrichment, Unit 2 Cycle 18 weighted average fresh bundle enrichment and the predicted EPU core weighted average fresh bundle enrichment are all less than the maximum licensed pellet enrichment of [[ ]] The NRC staff has determined that the core design for PBAPS, Units 2 and 3, is established in accordance with NRC-approved methodology for each core reload and therefore the EPU core design at PBAPS is acceptable.

Fuel Thermal Margin Monitoring

The CLTR (Reference 20) states that the percent power level above which fuel thermal margin monitoring is required may change with EPU. The PBAPS plant-specific changes with respect to fuel thermal margin monitoring are evaluated below in SE Section 3.3.

Thermal Limits Assessment

As discussed in PUSAR Section 2.8.2.2, the effect of EPU on the MCPR operating limits and on the MAPLHGR and LHGR limits for PBAPS varies from no effect to a very slight effect. Operating limits are set to ensure regulatory and/or safety limits are not exceeded for a range of postulated events such as transients and LOCA. The licensee stated that a representative equilibrium core was used for the EPU evaluation of thermal limits.

As discussed in PUSAR Section 2.8.2.2.1, safety limit minimum critical power ratio (SLMCPR) is affected slightly by EPU due to the flatter power distribution inherent in the increased power level. The power uprate flatter power distribution causes an increase in the SLMCPR less than 0.02 per ELTR1 (Reference 21). Cycle-specific SLMCPR calculations are evaluated for each reload and establish or confirm cycle-specific limits, as is currently the practice. The licensee stated that the SLMCPR will be established in accordance with approved methodology for each reload, as required by ELTR1.

As discussed in PUSAR Section 2.8.2.2.2, the MCPR operating limit (OLMCPR) is calculated by adding the change in MCPR due to the limiting AOO event to the SLMCPR and is determined on a cycle-specific basis from the results of the reload transient analysis. The effect of EPU on the AOO events is addressed in PUSAR Section 2.8.5 and evaluated by the NRC staff below in SE Section 2.8.5. The licensee stated in Supplement 6 to the EPU LAR (Reference 7) that the impact of EPU upon the PBAPS OLMCPR is expected to be an increase of less than 0.03 and that this change is attributable to changes in void and scram reactivity response caused by flattening of the radial power distribution.

As discussed in PUSAR Section 2.8.2.2.3, EPU operating conditions do not usually affect the MAPLHGR operating limit. The MAPLHGR operating limit ensures that the plant does not exceed regulatory limits established in 10 CFR 50.46 or by the fuel design limits. The MAPLHGR operating limit is determined by analyzing the limiting LOCA for the plant. The licensee stated that no change in the MAPLHGR limit is required for EPU for single recirculation loop operation or dual recirculation loop operation.

As discussed in PUSAR Section 2.8.2.2.4, the LHGR operating limit (OLLHGR) is determined from the fuel thermal-mechanical design methodology and is not affected by EPU.

The NRC staff reviewed the PBAPS EPU PUSAR along with the RAI responses in Supplement 6 to the EPU LAR (Reference 7). The staff finds that the licensee has appropriately considered the potential effects of EPU operation on the SLMCPR, OLMCPR, MAPLHGR and the OLLHGR. The staff concludes that there is reasonable assurance that these limits will be appropriately established for each reload based on cycle-specific analyses and use of NRC-approved methodologies.

As discussed in PUSAR Section 2.8.2.2.5, based on Section 9.1.2 of the CLTR, power and flow dependent limits are not affected by EPU. The operating MCPR and LHGR thermal limits are modified by a flow factor when the plant is operating reduced core flow. This modification is primarily based upon an evaluation of the slow recirculation increase event. The current PBAPS analysis is based upon a conservative flow runup rod line that bounds operation to the rod line documented in Section 1.2 of the PUSAR. Similarly, the thermal limits are modified by a power factor when the plant is operating at less than 100% power. The NRC staff finds the power and flow dependent limits at PBAPS meet all CLTR dispositions.

Reactivity Characteristics

As discussed in PUSAR Section 2.8.2.3, the higher core energy requirements of EPU may reduce the hot excess reactivity and reduce operating shutdown margin (SDM). The PUSAR further stated that, based on experience with previous plant-specific power uprate submittals, the required hot excess reactivity and SDM can be achieved for EPU through appropriate fuel and core design. As discussed above in SE Section 2.8.1, PBAPS uses GNF2 fuel. As such, the fuel design for EPU is evaluated on a plant-specific basis in accordance with ELTR1 (Reference 21). The fuel design limits for the GNF2 fuel are established in accordance with GESTAR II (Reference 68).

As discussed in Section 5.7.1 of ELTR1, all minimum SDM requirements apply to cold shutdown conditions and will be maintained without change. Checks of cold SDM based on standby liquid control system boron injection capability and shutdown using control rods with the most reactive control rod stuck out will be made.

As discussed in ELTR1, fuel cycle redesign for EPU can result in sufficient excess reactivity to match the desired cycle length. The increase in hot reactivity may result in less hot-to-cold reactivity difference and, therefore, smaller cold SDMs. However, this loss in margin can be accommodated through core design. If needed, a bundle design with improved SDM characteristics can be used to preserve the flexibility between hot and cold reactivity requirements for future cycles.

ELTR1 further states that reload fuel cycle analysis and core design for operation at the EPU power level optimize the energy requirement and power distribution so that the core and fuel performance characteristics are met through fuel loading strategy and control rod patterns.

Information regarding the specific analyses performed each cycle to demonstrate conformance to the fuel's thermal limits and to ensure that the SDM will meet the TS requirements under EPU conditions was provided on pages 8 through 14 of Attachment 1 to Supplement 6 to the EPU LAR (Reference 7).

The NRC staff finds that application of the GESTAR II methodology provides additional assurance of adequate SDM beyond the limits prescribed by the PBAPS TSs. The NRC staff concludes that since plant reactivity margins are established in accordance with approved methodology for each core reload, the assessment of reactivity margins for PBAPS is acceptable.

Applicability of GE Methods to Expanded Operating Domains

GE-Hitachi Nuclear Energy Americas LLC (GEH) licensing topical report NEDC-33173P-A (Reference 69, referred to as the interim methods licensing topical report (IMLTR)) provides the basis for the application of the suite of GEH and Global Nuclear Fuel (GNF) computational methods to perform safety analyses relevant to EPU. Since the approval of IMLTR, GEH provided supplemental information and modified the original limitations and conditions stated in

Section 9.0 of the NRC staff's SE for IMLTR concerning additional topics to be addressed in EPU applications (Reference 70). Appendix A of the PUSAR provides a summary disposition of these limitations and conditions. IMLTR is applicable to the GNF2 fuel design (i.e., the PBAPS fuel for the EPU core).

Limitation and Condition 9.17 of the IMLTR (Reference 69) requires the bypass voiding to be evaluated on a cycle-specific basis to confirm that the void fraction remains below 5% for EPU and MELLLA+. As discussed in PUSAR Section 2.8.2.4.1, the licensee plans to use the ISCOR (approved by NRC for stability calculations) methodology to evaluate bypass voiding. ISCOR conservatively calculates hot bypass channel voiding using its direct moderator-heating model and provides no credit for cross-flow while applying additional conservatism with bounding 4-bundle peaking. The use of ISCOR is a more efficient and accurate process compared to the use of TRACG and it typically demonstrates margin to the 5% bypass void fraction requirement at the local power range monitor (LPRM) D Level. The licensee stated in PUSAR Section 2.8.2.4.1 that if the resulting bypass void fraction is found to exceed the 5% requirement when evaluated on a cycle-specific basis, it is acceptable to relax the conservative ISCOR input assumptions as long as the overall approach can be demonstrated to remain conservative. The licensee further stated that it is also acceptable to perform a cycle-specific TRACG analysis with consideration of assumptions that will tend to maximize bypass void fraction. The NRC staff found this procedure acceptable for disposition of IMLTR Limitation and Condition 9.17. Results show that bypass voiding associated with the representative equilibrium GNF2 core is shown to be [[ ]] when operating at steady state conditions within the MELLLA boundary. This meets the disposition to Limitation and Condition 9.17.

Limitation and Condition 9.3 of the IMLTR (Reference 69) requires plant-specific EPU applications to confirm that the core thermal power to core flow ratio will not exceed 50 megawatts thermal (MWt) per million pounds mass (Mlbm) per hour (hr) at the low flow point at rated power (e.g., EPU: 100% Power/99.0% Flow) statepoint in the allowed operating domain. For plants that exceed the power-to-flow value of 50 MWt/Mlbm/hr, the application needs to provide a power distribution assessment to establish that neutronic methods axial and nodal power distribution uncertainties have not increased. As discussed in Section 2.8.2.4.2 of the PUSAR, for the proposed PBAPS EPU, the resulting core thermal power to total core flow ratio at 100% rated core power and 99% of rated core flow, under EPU conditions, is 38.9 MWt/Mlbm/hr. The licensee stated that the power-flow map is independent of fuel design and does not change from cycle to cycle. Therefore, the power-to-flow ratio for PBAPS's future EPU cycles will also remain below 50 MWt/Mlbm/hr at this statepoint. The NRC staff finds that the power-to-flow ratio analysis is consistent with the GEH letter discussing the implementation of methods limitations from NEDC-33173P (Reference 70).

Limitation and Condition 9.6 of the IMLTR (Reference 69) requires the plant-specific R-factor calculation at a bundle level be consistent with lattice axial void conditions expected for the hot channel operating state. The R-factor is a parameter that accounts for the effects of the fuel rod power distributions and the fuel assembly local spacer and lattice critical power characteristics. The R-factor formulation for a given fuel rod location depends on the power of that rod, as well as the powers of the surrounding rods. As discussed in PUSAR Section 2.8.2.4.3, the GNF2 bundle R-factors generated for the licensee's evaluation are consistent with GNF standard design procedures, which use an axial void profile shape with 60% average in-channel voids. This is consistent with lattice axial void conditions expected for the hot channel operating state.

Figure 2.8-19 of the PUSAR illustrates the fuel bundle average void history corresponding to hot channels with the limiting MCPRs from each cycle exposure statepoint of the PBAPS EPU core. This figure demonstrates that the generic R-factor profile, with an average void fraction of 0.60, is representative of the MCPR-limiting void conditions predicted by the PANAC11 code. The NRC finds that the information provided in the PUSAR, as discussed above, demonstrates that Limitation and Condition 9.6 of the IMLTR is met.

Limitation and Condition 9.24 of the IMLTR (Reference 69) requires plant-specific EPU applications to provide a prediction of key parameters for cycle exposures for operation at EPU. The following parameters: (1) Maximum Bundle Power; (2) Flow for Peak Bundle Power; (3) Exit Void Fraction for Peak Power Bundle; (4) Maximum Channel Exit Void Fraction; (5) Core Average Exit Void Fraction; (6) Peak LHGR; and (7) Peak Nodal Exposure are shown in PUSAR Figures 2.8-1 through 2.8-6 and Table 2.8-1. The PBAPS data are plotted with the available EPU experience base as required by Limitation and Condition 9.24. Quarter core maps with mirror symmetry are plotted in Figures 2.8-7 through 2.8-18 of the PUSAR showing bundle power, bundle operating MCPR, and LHGR for beginning-of-cycle, middle-of-cycle, and end-of-cycle. The NRC finds that the information provided in the PUSAR, as discussed above, demonstrates that Limitation and Condition 9.24 of the IMLTR is met.

Limitation and Condition 9.13 of the IMLTR (Reference 69) requires review and approval of the use of 10 weight percent Gadolinium (Gd) for EPU applications. As stated in PUSAR Section 2.8.4.2.5, for PBAPS, the maximum burnable poison (Gd) concentration used is 8.0 weight percent. Therefore, Limitation and Condition 9.13 of the IMLTR is not applicable for the proposed PBAPS EPU.

Limitation and Condition 9.21 of the IMLTR (Reference 69) requires that plants implementing EPU or MELLLA+ with mixed fuel vendor cores provide plant-specific justification for extension of GE's analytical methods or codes. As discussed in PUSAR Section 2.8.2.4.6, the proposed EPU for PBAPS will not use mixed cores. Therefore, Limitation and Condition 9.21 of the IMLTR is not applicable.

Limitation and Condition 9.22 of the IMLTR (Reference 69) requires that for any plant-specific applications of TGBLA06 with fuel-type characteristics not covered in the IMLTR review, GE needs to provide assessment data similar to that provided for the GEH/GNF fuels. The IMLTR review is applicable to all GEH/GNF lattices up to GNF2. Fuel lattice designs, other than GEH/GNF lattices up to GNF2, with certain design characteristics (discussed on page A-9 of Appendix A to the PUSAR), are not covered by the IMLTR review. As discussed in PUSAR Section 2.8.2.4.7, the proposed EPU for PBAPS will not use mixed cores. Therefore, Limitation and Condition 9.22 of the IMLTR is not applicable.

The NRC staff has reviewed the applicability of all applicable limitations and conditions for the IMLTR and has determined that the licensee has complied with the disposition of all applicable limitations and conditions per References 69 and 70.

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 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. 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 final GDCs 10 and 12, and draft GDCs 6, 8, 12, 13, 14, 15, 27, 28, 29, 30, 31 and 32. 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) final 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) final 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 RS-001.

Technical Evaluation

2.8.3.1 Stability Protection

2.8.3.1.1 Option III - OPRM Trip Enabled Region and Trip Setpoint

PBAPS has adopted Option III for long-term stability (LTS). The stability Option III hardware for PBAPS is fully integrated into the NUMAC™ Power Range Neutron Monitoring (PRNM) System.

Option III requires the combination of local power range monitor (LPRM) signals in a series of oscillation power range monitor (OPRM) channels, which are similar in nature to the existing average power range monitor (APRM) channels, differing only on the LPRM grouping. APRM channels attempt to average LPRM signals from all over the core. OPRM channels average LPRM signals from specific regions in the core, so that they can detect regional (out-of-phase) oscillations. APRM channels are not sensitive to out-of-phase oscillations because they average them out. The LPRM groupings in the OPRM channels are designed to avoid this problem.

The PBAPS Option III hardware combines the LPRM signals and evaluates the cell signals with instability detection algorithms. The Period Based Detection Algorithm (PBDA) is the only algorithm credited in the Option III licensing basis. Two defense-in-depth algorithms, referred to as the Amplitude Based Algorithm (ABA) and the Growth Rate Algorithm (GRA), offer a high degree of assurance that fuel failure will not occur as a consequence of stability related oscillation. As discussed in GE Nuclear Energy, Licensing Topical Report, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications," dated August 1996 (ADAMS Accession No. ML14093A210), both ABA and GRA are not needed to ensure compliance with the SLMCPR. They provide protection for oscillation characteristics that have not been observed and are not expected to occur. Per the CLTR, plants implementing Option III must demonstrate that the Option III trip setpoint is adequate to provide SLMCPR protection for anticipated reactor instability. This evaluation is dependent upon the core and fuel design and is performed for each reload.

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 OLTP and core flow ≤ 60 percent rated core flow. The CLTR states that the Option III trip setpoint may be affected by EPU operating conditions. For CPPU, the PBAPS OPRM trip-enabled region is rescaled to maintain the same absolute power/flow region boundaries. Because the rated core flow is not changed, the 60 percent core flow boundary is not rescaled. The 29.5% CLTP trip-enabled boundary is rescaled to the 26.2% EPU thermal power limit using the CLTP/EPU ratio provided in CLTR.

2.8.3.1.2 Option III - Hot Channel Oscillation Magnitude

As described in the CLTR, since PBAPS uses the Option III LTS Solution, [[

]] Therefore, no changes to the PBAPS currently licensed Option III stability solution hardware and software algorithms are required for EPU.

The OPRM trips that are enabled for PBAPS are the licensing basis Period Based Detection Algorithm (PBDA) as well as the Growth Rate Algorithm (GRA), and Amplitude Based Algorithm (ABA) defense-in-depth features. The algorithms for the LTS Option III solution are described in NEDO-32465-A, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications." The OPRM amplitude setpoint calculation is comprised of three components as defined in NEDO-32465-A. The calculation for hot channel oscillation magnitude (HCOM) is performed using approved GE methodology. The generic DIVOM (delta CPR over initial CPR versus oscillation magnitude) calculations performed in NEDO-32465-A used the earlier TRACG02 version and PANAC10 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 TRACG04/PANAC11 methodology produces stability results for core-wide oscillation mode that are essentially the same or more conservative than the ones obtained using TRACG02/PANAC10 methodology. As provided in Supplement 9 to the EPU LAR (Reference 10), the DIVOM slope calculated for the EPU equilibrium core is [[ ]], which is acceptable since it is above the generic DIVOM slope guidance given in NEDO-32465-A. The DIVOM slope is calculated as part of the cycle-specific reload licensing analysis. Therefore, it will be evaluated on a cycle-specific basis.

The primary mechanism that impacts the instrumentation readings is bypass boiling. The primary effect of voiding in the bypass region on the LPRM neutron detectors is to reduce the detector response assuming the same power in the adjacent fuel. This reduction in detector response is due to a decrease in the moderation caused by the presence of voids, which decreases the thermal neutron flux incident on the detectors for the same neutron flux generated in the adjacent fuel. Thus, bypass voiding creates a calibration issue. Per Limitation 18 of NEDC-33173-P-A, the NRC staff concluded that that the presence of bypass voiding at the low-flow conditions where instabilities are likely can result in calibration errors of less than 5% for OPRM cells and less than 2% for APRM signals. These calibration errors must be accounted for while determining the setpoints for any detect and suppress long-term methodology. PBAPS incorporated a 5% calibration error on the OPRM setpoints to address bypass voiding uncertainty at low-flow conditions, which translates to an approximate 0.01 decrease in OPRM amplitude setpoint. Additionally, an example calculation of OPRM setpoint for the EPU cycle, including an uncertainty term reflecting the possible LPRM miscalibration due to bypass voiding, was provided in Supplement 9 to the EPU LAR. The methodology provided in Supplement 9 will be used to determine the cycle-specific OPRM setpoint reported in the Supplemental Reload Licensing Report. This method is acceptable to the NRC staff. The APRM system is not used for detection and suppression of thermal-hydraulic oscillations; therefore, there is no effect of APRM calibration errors on the Option III scram setpoint.

2.8.3.1.3 Backup Stability Protection Evaluation

As discussed in PUSAR Section 2.8.3.1.3, PBAPS implements backup stability protection (BSP) as the stability licensing basis should the Option III OPRM system be declared inoperable. The BSP evolved from the stability Interim Corrective Actions (ICAs), which restrict plant operation in the high power, low core flow region of the BWR power/flow operating map. The ICAs provide guidance that reduces the likelihood of an instability event by limiting the period of operation in regions of the power/flow map most susceptible to thermal-hydraulic instability.

The BSP regions are calculated on a cycle-specific basis in accordance with the guidance provided in OG02-0119-260, "Backup Stability Protection (BSP) for inoperable Option III Solution," dated July 17, 2002. The GE ODYSY code is used for the calculation of decay ratios and is approved by the NRC staff. 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. Cycle-specific BSP regions are determined and documented in the Supplemental Reload Licensing Report. The BSP region intercepts with the Natural Circulation Line (NCL) and with the High Flow Control Line (HFCL) are the same as or more conservative than the ICA region intercepts in absolute power and core flow. The BSP regions consist of two regions (I-Scram and II-Controlled Entry), which are reduced from the three ICA regions (I-Scram, II-Exit and III-Controlled Entry (see BWROG-94078). A generic evaluation was performed for the ICAs (Section 3.2.1 of ELTR2), which is applicable for EPU. The bounding plant-and cycle-specific BSP region endpoints must enclose the corresponding base BSP region endpoints on the HFCL and the NCL. The proposed BSP Scram and Controlled Entry region boundaries may be constructed by connecting the corresponding bounding endpoints on the HFCL and NCL using the Modified Shape Function (MSF) (see GE LTR NEDE-33213P-A, "ODYSY Application for Stability Licensing Calculations Including Option I-D and II Long Term Solutions," dated April 2009 (ADAMS Accession No. ML091100207)).

PBAPS completed a GNF2 equilibrium demonstration analysis to calculate the BSP endpoints for nominal feedwater (FW) temperature and minimum FW temperature. The limiting endpoints in this calculation were used to construct the BSP regions for nominal FW temperature and minimum FW temperature. The NRC staff finds this method acceptable because: (1) PBAPS will be using entirely GNF2 fuel for its EPU cores; (2) the equilibrium EPU core is expected to be representative of uprated core designs; and (3) BSP regions are calculated or confirmed on a cycle-specific basis.

2.8.3.2 Anticipated Transient without Scram with Core Instability

The effects of an anticipated transient without scram (ATWS) with core instability event occur at natural circulation following a recirculation pump trip. It is initiated at approximately the same power level as a result of EPU operation because the MELLLA upper boundary is not increased. The core design necessary to achieve EPU operations may affect the susceptibility to coupled thermal-hydraulic/neutronic core oscillations at the natural circulation condition, but would not significantly affect the event progression.

CPPU allows plants to increase their operating thermal power, but does not allow an increase in control rod line. Several factors affect the response of an ATWS instability event, including operating power and flow conditions and core design. The limiting ATWS core instability presented in NEDC-32047-A, "ATWS Rule Issues Relative to BWR Core Thermal- Hydraulic Stability," June 1995, and NEDO-32164, "Mitigation of BWR Core Thermal-Hydraulic Instabilities in ATWS," December 1992, was performed for an assumed plant initially operating at OLTP and the MELLLA minimum flow point. NEDO-32164 indicates that for an unmitigated case, a small fraction of the core experiences locally high peak clad temperature (dryout) and some fuel damage cannot be precluded. For the mitigated case (reduction of reactor water level to reduce core inlet subcooling and direct injection of boron in the presence of power oscillation) extended dryout was not expected. The void reactivity coefficient, fuel response time (fuel rod diameter), and pressure loss coefficients are the parameters important to determining the reactor stability. It also indicates that initial operating conditions of feedwater heater out of service (FWHOOS) and final feedwater temperature reduction (FFWTR) do not significantly affect the ATWS instability response. The limiting ATWS evaluation assumes that all FW heating is lost during the event and injected FW temperature approaches the lowest achievable main condenser hot well temperature. The minimum condenser hot well temperature is not affected by FWHOOS or FFWTR. [[

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PBAPS currently applies emergency operating guidelines based on BWR Owners' Group Emergency Procedure and Severe Accident Guidelines, Revision 2 (BWROG EPGs/SAGs). The NRC staff conducted an audit on November 8, 2013, and reviewed the PBAPS ATWS procedures and witnessed two ATWS events in the plant simulator (ADAMS Accession No. ML13347B076, non-publicly available). All events were handled properly by the operators and the reactor was successfully shutdown without violating the ATWS criteria, which are based on core coolability, pressure boundary limits, and radiation release from containment.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the thermal and hydraulic design of the core and the RCS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the thermal and hydraulic design and demonstrated that the design: (1) has been accomplished using acceptable analytical methods; (2) is a proven design; (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 final GDCs 10 and 12 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to thermal and hydraulic design.

2.8.4 Emergency Systems

2.8.4.1 Functional Design of Control Rod Drive System

Regulatory Evaluation

The NRC staff's review covered the functional performance of the control rod drive (CRD) system 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 CRD cooling system to ensure that it will continue to meet its design requirements. The NRC's acceptance criteria are based on: (1) draft GDCs 40 and 42, insofar as they require that protection be provided for ESFs against the dynamic effects that might result from plant equipment failures, as well as the effects of a LOCA; (2) draft GDC-26, insofar as it requires that the protection system be designed to fail into a safe state; (3) draft GDC-31, insofar as it requires that the reactivity control systems be capable of sustaining any single malfunction without causing a reactivity transient, which could result in exceeding acceptable fuel damage limits; (4) draft GDCs 27 and 28, insofar as they require that at least two independent reactivity control systems be provided, with both systems capable of making and holding the core subcritical from any hot standby or hot operating condition sufficiently fast to prevent exceeding acceptable fuel damage limits; (5) draft GDCs 29 and 30, insofar as they require that at least one of the reactivity control systems be capable of making and holding the core subcritical under any condition sufficiently fast to prevent exceeding acceptable fuel damage limits; (6) draft GDC-32, insofar as it requires that limits, which include considerable margin, be placed on the maximum reactivity worth of control rods or elements and on rates at which reactivity can be increased to ensure that the potential effects of a sudden or large change of reactivity cannot: (a) rupture the reactor coolant pressure boundary; or (b) disrupt the core, its support structures, or other vessel internals sufficiently to impair the effectiveness of emergency core cooling; and (7) 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.

Technical Evaluation

As discussed in PUSAR Section 2.8.4.1, the CRD system is used to control core reactivity by positioning neutron absorbing control rods within the reactor and to scram the reactor by rapidly inserting withdrawn control rods into the core.

As discussed in Section 2.5 of the NRC staff's SE approving the CLTR, the CRD system was [[ ]] evaluated in Section 5.6.3 and J.2.3.3 of ELTR1 and in Section 4.4 of Supplement 1 to ELTR2. The [[ ]] evaluation concluded that the CRD systems for BWR/2-6 plants are acceptable for EPU as high as 20% above the original rated power.

As discussed above in SE Section 1.2, PBAPS, Units 2 and 3, are of the BWR/4 design and the proposed EPU represents an increase of approximately 20% above the original licensed thermal power level. Therefore, as stated in Section 2.5 of the NRC staff's SE for the CLTR, no additional plant-specific calculations are required beyond confirmatory evaluation. The licensee provided the results of its confirmatory evaluation in PUSAR Section 2.8.4.1. The topics addressed in the licensee's evaluation are as follows:

- Scram Time Response
- CRD Positioning
- CRD Cooling
- CRD Integrity Assessment

The NRC staff's evaluation for each of these topics is provided below.

Scram Time Response

As discussed in Section 2.8.4.1.1 of the PUSAR, at normal operating conditions, the CRD hydraulic control unit accumulator supplies the initial scram pressure and, as the scram continues, the reactor becomes the primary source of pressure to complete the scram. Because the normal reactor dome pressure for EPU does not change, the scram time performance relative to current plant operation will be the same.

The PUSAR also states that [[

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The licensee concluded in PUSAR Section 2.8.4.1.1 that the CRD system control rod scram at PBAPS is confirmed to be consistent with the generic description provided in the CLTR for pre-BWR/6 plants.

PBAPS, Units 2 and 3, TS 3.1.4, "Control Rod Scram Times," provides surveillance requirements with specific scram time acceptance criteria as shown in TS Table 3.1.4-1. As discussed in the Bases for TS 3.1.4, surveillance of each individual control rod's scram time ensures the scram reactivity assumed in the DBA and transient analyses can be met. The licensee has not requested to change the requirements in TS 3.1.4 as part of the proposed EPU.

Based on the confirmation provided by the licensee that PBAPS meets the CLTR disposition and the requirements in TS 3.1.4 for control rod scram time testing, the NRC staff concludes that the proposed EPU is acceptable with respect to scram time response.

CRD Positioning

As discussed in Section 2.5.2 of the NRC staff's SE for the CLTR, and PUSAR Section 2.8.4.1.2.1, the increase in power at EPU operating conditions (i.e., with reactor dome pressure unchanged), will result in [[
]] and the automatic operation of the system flow control valve maintains the required drive water pressure. Therefore, the CRD positioning function is not affected under EPU conditions.

The licensee confirmed the CLTR disposition by providing plant-specific information in PUSAR Section 2.8.4.1.2.1. The licensee stated that plant operating data for PBAPS, Units 2 and 3, has confirmed that [[
]]

Based on the confirmation provided by the licensee that PBAPS meets the CLTR disposition, the NRC staff concludes that the proposed EPU is acceptable with respect to CRD positioning.

Note, as discussed in Section 2.5.2 of the NRC staff's SE for the CLTR, the normal CRD positioning function is an operational consideration and is not a safety-related function.

CRD Cooling

As discussed in PUSAR Section 2.8.4.1.2.2, and Section 2.5.2 of the CLTR, EPU operating conditions will result in [[
]] and the automatic operation of the CRD system flow control valve maintains the required cooling water flow rate. Therefore, the CRD cooling function is not affected under EPU conditions.

The licensee confirmed the CLTR disposition by providing plant-specific information in PUSAR Section 2.8.4.1.2.2. The licensee stated that plant operating data for PBAPS, Units 2 and 3, has confirmed that [[
]]

Based on the confirmation provided by the licensee that PBAPS meets the CLTR disposition, the NRC staff concludes that the proposed EPU is acceptable with respect to CRD cooling.

Note, as discussed in Section 2.5.2 of the CLTR, the normal CRD cooling function is an operational consideration and is not a safety-related function.

CRD Integrity Assessment

Section 2.5.3 of the CLTR states that [[ ]] on CRD integrity. However, transient pressures due to uprated power may create higher pressure loadings. With respect to the CRD design, the CLTR states that the postulated abnormal operating condition assumes a failure of the CRD system pressure-regulating valve that applies the maximum pump discharge pressure to the CRD mechanism (CRDM) internal components. Section 2.5.3 of the NRC staff's SE for the CLTR states that confirmation of bounding existing design basis or plant-specific evaluations accounting for design basis mechanical loads affecting the CRDMs would provide the basis to ensure that the CRDMs meet design basis and performance requirements at EPU conditions.

The licensee confirmed in PUSAR Section 2.8.4.1.3 that the mechanical loadings on the CRDMs are acceptable under EPU conditions. Specifically, [[

]]

Based on the confirmation provided by the licensee that PBAPS meets the CLTR disposition, the NRC staff concludes that the proposed EPU is acceptable with respect to CRD integrity.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the functional design of the CRD system. 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 postulated accidents will be maintained following the implementation of the proposed EPU. The NRC staff further concludes that the licensee has demonstrated that sufficient cooling exists to ensure the system's design bases will continue to be followed upon implementation of the proposed EPU. Based on this, the NRC staff concludes that the fuel system and associated analyses will continue to meet the requirements of draft GDCs 26, 27, 28, 29, 30, 31, 32, 40 and 42, 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 CRD system.

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 reactor protection system. 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) draft GDC-9, insofar as it requires that the RCPB be designed and constructed so as to have an exceedingly low probability of gross rupture or significant leakage throughout its design lifetime; and (2) final GDC-31, insofar as it requires that the RCPB be designed with sufficient margin to assure that it behaves in a nonbrittle manner and that the probability of rapidly propagating fracture is minimized. Specific review criteria are contained in SRP Section 5.2.2.

Technical Evaluation

In Section 2.8.4.2 of the PUSAR, the licensee provides an evaluation of the effects of the proposed EPU on the PBAPS overpressure protection systems. The evaluation characterizes the impact of the proposed EPU by stating, "the increased core steam generation causes an increase in the pressurization during some transient events." An analysis, performed using NRC-approved methods, confirms that the plant can acceptably mitigate the limiting overpressure AOO at the proposed, uprated condition. Further, reload licensing analyses demonstrate that the mitigating capabilities remain acceptable on a cycle-specific basis. This review establishes that the licensee has acceptably evaluated the overpressure protection systems, and that the predicted system performance remains within the NRC's acceptance criteria.

A reactor overpressure condition could result from a load rejection or similar event in the steam and power conversion system, a spurious main steam isolation valve closure, or a malfunction in the control systems causing feedwater supply or recirculation flow to exceed steam demand. The overpressure protection system and the reactor protection system (RPS) mitigate the adverse effects of such events. Overpressure protection at PBAPS is described in UFSAR Section 4.4, "Nuclear System Pressure Relief System." The system includes two main steam safety valves (SSVs) and 11 safety relief valves (SRVs). The licensee proposes to install an additional SSV on each unit to provide additional overpressure protection for ATWS events as discussed in Enclosure 9a to Attachment 9 to the EPU LAR. The SSVs and SRVs are located on the main steam lines. The SSVs discharge to the drywell airspace and the SRVs discharge to the suppression pool. In addition to the safety and relief valves, the RPS is designed to detect conditions indicating an increase in vessel pressure and trip the reactor. The RPS is equipped with scram signals on reactor vessel water level, turbine stop, and main steamline isolation valve position indication, turbine speed, neutron flux, and reactor pressure as shown in PBAPS TS Table 3.3.1.1-1.

As proposed, the PBAPS TSs will require that the safety function of any combination of 13 SRVs and SSVs shall be operable. The licensee will install an additional safety valve on each unit, bringing the number of safety valves from 2 to 3. Surveillance Requirement 3.4.3.1 will reflect this plant modification (see SE Section 3.14 for evaluation of the TS change).

The SRVs have setpoints as follows: 4 at 1135 psig; 4 at 1145 psig; and 3 at 1155 psig. All 3 SSVs will be set at 1260 psig. Although TS SR 3.4.3.1, as originally proposed in Attachment 2 to the EPU LAR (Reference 1), shows each SRV and SSV with allowable as-found lift setpoint tolerance values equivalent to ±1% of the associated setpoints, the licensee also proposed (via a separate LAR dated June 10, 2013, ADAMS Accession No. ML13175A109) to increase the tolerance values to ±3%. On May 5, 2014, the NRC staff approved the separate LAR that, in part, revised the SR 3.4.3.1 to increase the allowable as-found SRV and SSV lift setpoint tolerance from ± 1% to ± 3 (Reference 115). With respect to the proposed EPU, the licensee clarified that the overpressure analyses assumed that the SRVs and SSVs had a 3% lift setpoint tolerance in Supplement 13 to the EPU LAR (Reference 14).

The licensee analyzed the ASME overpressure events using the NRC-approved ODYN code (NEDO-24154, "Qualification of the 1-Dimensional Core Transient Model for Boiling Water Reactors"). The analysis assumes that the reactor dome pressure is at the maximum permissible value of 1068 pounds per square inch atmospheric (psia). The analysis also assumes that one SRV is out of service. Although the licensee states that this assumption is conservative, the NRC staff verified that the TSs do, in fact, permit one valve to be out of service. Therefore, the NRC concluded that the analytic assumption was acceptable because it reflected the minimum TS-permitted SRV/SSV configuration.

The licensee analyzed a spurious closure of the main steamline isolation valves (MSIVs). The analysis assumes that the reactor scram signal from the MSIV position indication fails, and the transient terminates on a high flux scram. [[

]]

The NRC staff verified that the MSIV closure with scram on high flux (MSIVF) event was limiting when compared to the other potentially limiting event, the turbine trip with no bypass and scram on high flux, by comparing results of ODYN analyses for each as shown in Attachment 2 to Supplement 9 to the EPU LAR (Reference 10). The comparison showed that peak vessel bottom and steam dome pressures for the MSIVF event were limiting by about 40 psi. The NRC staff concluded, based on this comparison, that the licensee had identified the limiting initiating event for the overpressure analysis.

Noting the above, the NRC staff's review and acceptance criteria are as follows (SRP 5.2.2):

- The analysis should be performed using acceptable analytic methods
- The minimum plant configuration permitted by plant TS should be analyzed
- The analysis should assume the failure of the first safety-grade reactor trip
- The peak pressure may not exceed 110-percent of the vessel design pressure
- TS Safety Limits may not be exceeded

The licensee's results indicated that a peak pressure of 1335 psig is reached. This pressure is less than the ASME Code allowable peak pressure of 1375 psig (i.e., 110% of the reactor design pressure of 1250 psig). The maximum reactor dome pressure is 1314 psig, well within the dome pressure safety limit of 1325 psig. Because the analyses: (1) assumed the failure of the direct scram; (2) were performed using acceptable analytic methods; (3) reflected the minimum TS-permitted plant configuration; and (4) indicated acceptable results, the NRC staff concluded that the proposed EPU is acceptable with respect to overpressure protection.

<u>Conclusion</u>

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the overpressure protection capability of the plant during 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 final GDC-31 and draft GDC-9 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to overpressure protection during power operation.

2.8.4.3 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 decay heat removal capability whenever the main feedwater system is isolated from the reactor vessel. In addition, the RCIC system may provide decay heat removal necessary for coping with a station blackout (SBO). The water supply for the RCIC system comes from the condensate storage tank, with a secondary supply from the suppression pool. The NRC staff's review covered the effect of the proposed EPU on the functional capability of the system. The NRC's acceptance criteria are based on: (1) draft GDC-40, insofar as it requires that protection be provided for ESFs against dynamic effects; (2) draft GDC-4, insofar as reactor facilities shall not share systems or components unless it is shown safety is not impaired by the sharing; (3) draft GDC-37, insofar as it requires that ESFs be provided to back up the safety provided by the core design, the RCPB, and their protective systems; (4) draft GDCs 51 and 57, insofar as they require that piping systems penetrating containment be designed with appropriate features as necessary to protect from an accidental rupture outside containment and the capability to periodically test the operability of the isolation valves to determine if valve leakage is within acceptable limits; and (5) 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.

Technical Evaluation

The RCIC system consists of a steam-driven turbine pump unit and associated valves and piping capable of delivering makeup water to the reactor vessel. Fluid removed from the reactor vessel following a shutdown from power operation is normally made up by the feedwater system, supplemented by inleakage from the control rod drive system. If the feedwater system is inoperable, the RCIC turbine pump unit starts automatically, or the operator starts it from the control room. The water supply for the RCIC system comes from the condensate storage tank (CST) with a secondary supply from the suppression pool. The system is described in PBAPS UFSAR Section 4.7.

According to the NRC SE approving ELTR2 (Reference 22), the RCIC system is designed specifically to mitigate the effects of a loss of feedwater flow event. The CLTR (Reference 20) characterizes the EPU effect on the RCIC system as follows:

> The higher decay heat changes the response of reactor water level following a loss of feedwater event in which high pressure core injection (HPCI) or high pressure core spray (HPCS) is assumed to fail. There is no change to the normal operating pressure or the SRV setpoints.

The loss of feedwater event is analyzed on a cycle-specific basis, meaning that the RCIC system capability is confirmed each cycle using NRC-approved analytic methods.

For the proposed EPU, the licensee evaluated RCIC system performance and hardware, and net positive suction head.

With regard to system performance, the licensee stated, in PUSAR Section 2.8.4.3.1, that there is no change to the normal reactor operating dome pressure, and the SRV setpoints remain the same. The NRC staff reviewed this evaluation in consideration of the RCIC performance specifications contained in the PBAPS UFSAR.

Since the EPU would increase the decay heat load, for which RCIC must, in some cases, provide cooling, the NRC staff requested that the licensee provide any new RCIC system requirements and explain how the RCIC system would meet any new criteria without changing the system performance. The licensee responded in Attachment 2 to Supplement 9 to the EPU LAR that the key requirement for RCIC was that the "system design injection rate must be sufficient for compliance with the system limiting criteria to maintain the reactor water level above Top of Active Fuel (TAF) at EPU conditions." The licensee also clarified that the RCIC performance analyses that had been performed to evaluate the EPU did not assume any increased RCIC flow capabilities, which confirmed that the RCIC system operating parameters for CLTP remain adequate for EPU conditions.

The NRC staff noted that the RCIC system is designed to restore the reactor water level while avoiding automatic depressurization system (ADS) timer initiation and MSIV closure activation functions associated with the low-low-low reactor water level setpoint (Level 1). The licensee stated in the PUSAR that the results of PBAPS plant-specific evaluation indicates that the RCIC system is capable of maintaining the water level outside the shroud above nominal Level 1 setpoint through a limiting loss of feedwater (LOFW) event at EPU conditions. The results of this event are evaluated in Section 2.8.5.2.3 of this SE. Since, as the licensee stated, "this requirement is intended to avoid unnecessary initiations of safety systems," and is not a safety-related design basis for the system, the NRC staff did not identify any issues with the licensee's disposition for Level 1 avoidance. Note, however, that the LOFW analysis indicates that the water level does not fall below the nominal Level 1 setpoint.

The NRC staff confirmed that this conclusion is consistent with the disposition contained in the CLTR (i.e., performance requirements for RCIC remain unchanged), and hence concluded that the evaluation was acceptable.

The effect of EPU with respect to the operation of the RCIC system during an SBO event is evaluated in SE Section 2.3.5.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the ability of the RCIC system to provide decay heat removal following an isolation of main feedwater event and an SBO event. 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 decay heat removal 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 draft GDCs 4, 37, 40, 51, and 57, and 10 CFR 50.63, following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the RCIC system.

2.8.4.4 Residual Heat Removal System

Regulatory Evaluation

The RHR system is used to cool down the RCS following shutdown. The RHR system is typically a low pressure system which takes over the shutdown cooling function when the RCS temperature is reduced. The NRC staff's review covered the effect of the proposed EPU on the functional capability of the RHR system to cool the RCS following shutdown and provide decay heat removal. The NRC's acceptance criteria are based on: (1) draft GDCs 40 and 42, insofar as they require that protection be provided for ESFs against dynamic effects; and (2) draft GDC-4, insofar as reactor facilities shall not share systems or components unless it is shown safety is not impaired by the sharing. Specific review criteria are contained in SRP Section 5.4.7 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

The RHR system is described in PBAPS UFSAR Section 4.8, "Residual Heat Removal System." The system's low pressure coolant injection (LPCI) mode is responsible for restoring and maintaining coolant inventory to ensure adequate post-LOCA core cooling. The PBAPS RHR system also provides suppression pool and containment spray cooling operating modes. Aside from post-accident operation, the RHR system is used to cool the reactor coolant system following reactor shutdown. The RHR system can also be used to assist with cooling the spent fuel pool. The evaluation in this subsection focuses specifically on the shutdown cooling (SDC) and fuel pool cooling assist modes of the RHR system. The LPCI mode is addressed in Section 2.8.5.6.2, and the suppression pool and containment spray cooling modes are addressed in Section 2.6.5, of this SE.

Section 4.8.5 of the PBAPS UFSAR summarizes the major RHR system design as follows:

> The major equipment of the RHRS [RHR system] consists of four heat exchangers, four main system pumps, and four high-pressure service water pumps for each unit... The equipment is connected by associated valves and piping, and the controls and instrumentation are provided for proper system operation...

The shutdown cooling mode of RHR is supported by TS operability requirements contained in LCOs 3.4.7 and 3.4.8. LCO 3.4.7, "Residual Heat Removal (RHR) Shutdown Cooling System - Hot Shutdown," requires two RHR shutdown cooling subsystems to be operable, and with no recirculation pump in operation, also requires at least one RHR shutdown cooling subsystem to be in operation. The LCO is applicable in Mode 3. LCO 3.4.8, "Residual Heat Removal (RHR) Shutdown Cooling System - Cold Shutdown," establishes similar requirements for Mode 4.

The increased decay and residual heat loads associated with EPU operation will require the RHR to remove an increased amount of decay heat. This can be accomplished by running the RHR system longer, or operating with greater RHR flow by running with more subsystems in service, for example.

In PBAPS UFSAR Section 4.8.6.1, the licensee indicates that the RHR system is used once the initial phase of nuclear system cooldown has been accomplished by dumping nuclear steam to the condenser. The UFSAR states that the SDC cooling subsystem is capable of completing cooldown to 125 °F in approximately 30 hours, and of maintaining the nuclear system at 125 °F so that the reactor can be refueled and serviced. The PUSAR states that the SDC analysis for the EPU determined that the time needed for cooling the reactor to 125 °F during normal reactor shutdown, with two SDC subsystems in service, is increased to 34.4 hours at EPU conditions. The licensee concluded that the increased time may affect outage planning, but that the increased time would have no effect on plant safety or design operating margins.

Section 3.10 of the CLTR states, "[b]ecause the power uprate increases the reactor decay heat, a longer time is required for the reactor cool down." However, the CLTR also concludes that the "longer SDC time does not have an effect on plant safety."

Regarding the fuel pool cooling assist mode, the spent fuel pool heat load also increases due to the increased decay heat generation associated with the EPU. However, the licensee evaluated the adequacy of the fuel pool cooling and cleanup system, as described in Section 2.5.3.1 of the PUSAR, and concluded that this system provides adequate cooling capacity at EPU conditions, meaning that the RHR fuel pool cooling mode can still provide supplemental capacity at EPU conditions.

The NRC staff review of the PUSAR and available PBAPS licensing basis documentation indicated that the requested EPU would extend the 30-hour cooldown time discussed in the UFSAR to 34 hours. Consistent with the CLTR, which indicates that a longer SDC time has no effect on plant safety, the NRC staff determined that the proposed EPU was acceptable with respect to the SDC mode of the RHR system. And, since the fuel pool cooling assist mode serves as a backup to the normal fuel pool cooling system, the NRC staff determined that the RHR system fuel pool cooling assist mode would not be adversely affected by the requested EPU. Based on these considerations, the NRC staff determined that the requested EPU was acceptable with respect to the RHR system.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the RHR system. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system and demonstrated that the RHR system will maintain its ability to cool the RCS following shutdown and provide decay heat removal. Based on this, the NRC staff concludes that the RHR system will continue to meet the requirements of draft GDCs 4, 40 and 42 following implementation of the proposed 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 standby liquid control (SLC) system provides backup capability for reactivity control independent of the control rod system. The SLC system 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) draft GDCs 27 and 28, insofar as they require that at least two independent reactivity control systems be provided, with both systems capable of making and holding the core subcritical from any hot standby or hot operating condition sufficiently fast to prevent exceeding acceptable fuel damage limits; (2) draft GDCs 29 and 30, insofar as they require that at least one of the reactivity control systems be capable of making and holding the core subcritical under any condition sufficiently fast to prevent exceeding acceptable fuel damage limits; and (3) 10 CFR 50.62(c)(4), insofar as it requires that the SLC system be capable of reliably injecting a borated water solution into the reactor pressure vessel at a boron concentration, boron enrichment, and flow rate that provides a set level of reactivity control. Specific review criteria are contained in SRP Section 9.3.5 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

The SLC system is described in PBAPS UFSAR Section 3.8, "Standby Liquid Control System." The system relies on positive displacement pumps to inject SLC solution into the reactor under ATWS conditions. The solution is an isotopically enriched sodium pentaborate solution at a concentration and isotopic enrichment sufficient to bring the reactor from full power to a shutdown condition at room temperature.

An EPU can affect SLC system performance in several ways. The higher energy core design may have different shutdown requirements, which could affect the boron concentration or boron-10 enrichment required for the standby liquid control solution. In addition, an EPU ATWS transient may require the SLC system to inject at a higher pressure than at non-uprated conditions. Associated with the limiting ATWS event, the suppression pool temperature may exhibit more limiting behavior relative to the heat capacity temperature limit, and the SLC system design can affect this behavior.

Based on the above considerations, the licensee evaluated the core shutdown margin, the SLC system performance and hardware, and the suppression pool temperature following the limiting ATWS event.

Core Shutdown Margin

Section 6.5 of the CLTR states, "the power increase alone does not affect the requirements for minimum reactor boron concentration." The licensee stated in Section 2.8.4.5.1 of the PUSAR that the ability of the SLC system boron solution to achieve and maintain safe shutdown is not a direct function of core thermal power, and therefore, is not affected by EPU. The PUSAR also indicates the boron shutdown concentration is unchanged for the EPU, and that the SLC system shutdown capability is re-evaluated for each fuel reload. Based on the EPU ATWS analyses, the licensee determined that the isotopic enrichment requirements for the SLC system will change from the current 61.92 atom-percent to 92 atom-percent boron-10.

The NRC staff reviewed the licensee evaluation and determined that the disposition regarding shutdown margin, as described in the PUSAR, is consistent with that discussed in the CLTR. Furthermore, the licensee stated that SLC system shutdown capability is re-evaluated for each fuel reload. The NRC verified that this evaluation is an element of the cycle-specific reload analysis process, which is NRC-approved (Reference 67).

Although the licensee proposes to increase the isotopic boron-10 enrichment, this increase is not necessarily related to shutdown margin requirements. In Attachment 1 to the EPU LAR, the licensee stated, in part, the following:

> Raising the [boron-10] isotopic enrichment for EPU increases the rate of negative reactivity inserted by the SLC System and results in a faster shut down of the reactor during the ATWS event. This results in a reduced heat load input into the suppression pool . . .

Based on the above information, the NRC staff determined that the proposed change in isotopic boron enrichment did not invalidate the CLTR disposition invoked by the licensee.

Since the licensee disposed the SLC system core shutdown requirements in accordance with the CLTR, and the licensee re-evaluates SLC system shutdown capability on a cycle-specific basis using NRC-approved methods, the NRC determined that the licensee's SLC system shutdown margin requirements evaluation was acceptable.

SLC System Performance and Hardware

As discussed in Section 2.8.4.5.2 of the PUSAR, as supplemented by the information in Section 4.0 of Attachment 1 to Supplement 27 to the EPU LAR (Reference 116), the licensee evaluated SLC system performance and hardware by performing plant-specific ATWS analyses for the EPU. The analyses are performed, in part, to establish that the SLC system injection initiation occurs at such a time that the SLC solution can inject into the reactor, and that the SLC system discharge piping relief valves would not open and cycle the boron solution back to the SLC tank. Although the ATWS performance analysis is reviewed in greater detail in Section 2.8.5.7 of this SE, the licensee determined, from the analysis, that the maximum reactor lower plenum pressure following the limiting ATWS event reaches 1191.3 psig at the time the SLC system is operating. The licensee stated that this corresponds to an SLC system discharge pressure of 1266 psig, with 75 psi pressure drop from the pump discharge through the injection line. The licensee assigns 184 psi margin for system flow, head losses for full injection, and cycling pressure pulsations, based on the setpoint of 1450 psig for the SLC system discharge relief valves. In this configuration, the SLC system supports ATWS mitigation within the acceptance criteria outlined in Section 2.8.5.7.

Because the licensee performed a plant-specific analysis that confirmed that the SLC system will support ATWS mitigation at EPU conditions, the NRC staff determined that the SLC system performance and hardware were acceptable with respect to the proposed EPU.

Suppression Pool Temperature

The licensee's proposed elimination of credit for containment accident pressure required examination of heat loads to the suppression pool, and the licensee determined that, in order to re-gain the required suppression pool temperature margin, the SLC system boron-10 enrichment would need to increase. The licensee performed the ATWS analyses assuming the revised SLC system operating parameters, as discussed above, and concluded that the suppression pool temperature during the ATWS events would decrease. The system response was evaluated using ODYN, as discussed in Section 2.8.5.7 of this SE; containment response is evaluated in accordance with the NRC-approved SHEX code as noted in Table 1-1 of the PUSAR. Since the licensee ensured, by modifying the SLC system operating parameters, that the suppression pool temperatures predicted under ATWS conditions would decrease to a level that ensures that the required temperature margins remain available at EPU conditions, the NRC staff determined that the proposed EPU was acceptable with respect to the suppression pool temperature response to ATWS in light of the revised SLC system operating parameters.

In summary, the NRC staff review confirmed that the licensee's evaluation of the SLC system for the proposed EPU was consistent with the dispositions contained in the CLTR. The licensee's evaluations were performed using NRC-approved analytic methods, and the required SLC system shutdown margin will be confirmed on a cycle-specific basis. Based on these considerations, the NRC determined that the proposed EPU was acceptable with respect to the SLC system performance.

The analyses discussed in this section reflect the proposed TS revisions for TS 3.1.7, "Standby Liquid Control System," as evaluated in Section 3.4 of this SE.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the SLC system 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 SLC system will continue to meet the requirements of draft GDCs 27, 28, 29 and 30, 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 SLC system.

2.8.5 Accident and Transient Analyses

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 shutdown margin. Any unplanned power level increase may result in fuel damage or excessive reactor system pressure. Reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered: (1) postulated initial core and reactor conditions; (2) methods of thermal and hydraulic analyses; (3) the sequence of events; (4) assumed reactions of reactor system components; (5) functional and operational characteristics of the reactor protection system; (6) operator actions; and (7) the results of the transient analyses. The NRC's acceptance criteria are based on: (1) draft GDC-6, insofar as it requires that the reactor core be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits; (2) draft GDCs 14 and 15, insofar as they require that the core protection system be designed to act automatically to prevent or suppress conditions that could result in exceeding acceptable fuel damage limits and that protection systems be provided for sensing accident situations and initiating the operation of necessary ESFs; and (3) draft GDC-29, insofar as they require that a reactivity control system be provided capable of preventing exceeding acceptable fuel damage limits. Specific review criteria are contained in SRP Section 15.1.1-4 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

Excessive heat removal transients can be caused by reducing the enthalpy of water flowing into the reactor vessel, or by increasing the steam flow out of the vessel. These events are discussed in PBAPS UFSAR Section 14.5.2, "Events Resulting in a Reactor Vessel Water Temperature Decrease," and in PBAPS UFSAR Section 14.5.4, "Events Resulting in a Reactor Vessel Coolant Inventory Decrease." The specific sections are as follows:

- Decrease in Feedwater Temperature, or Loss of Feedwater Heating (PBAPS UFSAR Section 14.5.2.3)
- Increase in Feedwater Flow, or Feedwater Controller Failure - Maximum Demand (PBAPS UFSAR Section 14.5.2.2)
- Increase in Steam Flow, or Pressure Regulator Failure (PBAPS UFSAR Section 14.5.4.1)
- Inadvertent Opening of a Main Steam Relief or Safety Valve (PBAPS UFSAR Section 14.5.4.2)

The PUSAR addresses each of these events consistent with the CLTR. Noting that PBAPS is currently using the GNF2 fuel design, the licensee also refers to ELTR1, since the CLTR dispositions are limited to GE14 and earlier fuel designs.

[[ ]]. Of the four events listed above, the loss of feedwater heating and the feedwater controller failure [[ ]] are analyzed. The other events are not. The licensee states, in the PUSAR, that the [[ ]].

The NRC staff reviewed the PBAPS UFSAR. The information contained in the UFSAR for these events is similar to that described in the PUSAR and ELTR1, in that the limiting events in this category are consistent. They are also consistent in that the [[ ]].

The PUSAR states that the loss of feedwater heating and the feedwater controller failure are confirmed to be within the PBAPS reload evaluation scope. The licensee provides the uncorrected change in critical power ratio (CPR) for these two events in Table 2.8-12 of the PUSAR. The information shows that, for the loss of feedwater heating, the uncorrected change in CPR is 0.13 for CLTP and 0.12 for EPU. Similarly, the uncorrected change in CPR for the feedwater controller failure to max demand is 0.24 for CLTP and 0.23 for EPU. The PUSAR also indicated that NRC-approved methods are used to perform these analyses. The methods for the feedwater controller failure are as described in GESTAR II (Reference 67), and the loss of feedwater heating is analyzed using PANACEA.

Since the limiting events in this category are analyzed on a cycle-specific basis using NRC approved methods, and since the PBAPS licensing basis is consistent with the disposition described in the PUSAR, the NRC staff determined that the licensee had adequately evaluated the effects of the proposed EPU with respect to the excessive cooling events. In addition, the NRC staff also confirmed that these dispositions are consistent with those contained in the CLTR; the analytic results provided in Table 2.8-12 confirm this. Based on these considerations, the NRC staff concluded that the licensee adequately addressed the proposed EPU with respect to the excessive heat removal events.

Conclusion

The NRC staff reviewed the licensee's analyses of the excess heat removal events described above and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of these events. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of draft GDCs 6, 14, 15, and 29 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) draft GDC-6, insofar as it requires that the reactor core be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits; and (2) draft GDC-29 insofar as it requires that a reactivity control system be provided capable of preventing exceeding acceptable fuel damage limits. Specific review criteria are contained in SRP Section 15.2.1-5 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

This category of transients includes Generator Load Rejection with Steam Bypass Failure (LRNBP), Turbine Trip with Steam Bypass Failure (TTNBP), Loss of Condenser Vacuum (LOCV), Total Main Steam Isolation Valve Closure with Direct Scram (total MSIV closure), Single Main Steam Isolation Valve Closure with Direct Scram (single MSIV closure), and Steam Pressure Regulator Failure - Downscale (Closed) (PRFD).

The ASME overpressure transients are evaluated as discussed in SE Section 2.8.4.2. These events, which are characterized as infrequent events rather than AOOs, assume the failure of the first safety-grade reactor trip signal. This section evaluates the AOOs in this category, the analyses of which are used to establish adequate thermal margin.

The remaining transients in this section are evaluated to ensure specified acceptable fuel design limits (SAFDLs) are not exceeded through establishing an operating limit of MCPR. The LRNBP event was analyzed. In this event, a loss of generator electrical load from high power conditions initiates a fast closure of the main turbine control valves. The turbine control valves close in approximately 0.08 seconds as discussed in PBAPS UFSAR Section 14.5.1.1. This in turn causes a sudden reduction in steam flow and results in a reactor pressure surge. Turbine control valve closure is sensed by the reactor protection system, and it activates the reactor scram. The results of this event show a delta-CPR of 0.27 as shown in PUSAR Table 2.8-12. This transient is the limiting event for MCPR among the analyzed set in PUSAR Table 2.8-12. This is used to establish OLMCPR for fuel thermal limit protection. As long as OLMCPR is not exceeded, SAFDLs are assured.

The TTNBP event was also analyzed. A turbine or other reactor system malfunction could initiate a turbine trip, abruptly stopping steam flow to the turbine. Once initiated, all of the main turbine stop valves close within about 0.10 second. Position switches on the turbine stop valves sense the trip and initiate reactor scram. Due to the longer stop valve closure time relative to the control valve closure time, this event is less severe than LRNBP. Analysis of TTNBP shows a delta-CPR of 0.26 as shown in PUSAR Table 2.8-12. Therefore, this event is bounded by the LRNBP event.

The total MSIV closure (i.e., all valves) and single MSIV closure events were also analyzed. MSIV closure can occur by various steam line or reactor system malfunctions and operator actions. As the MSIVs close, position switches on the MSIVs sense the valve closure and initiate reactor scram. MSIV closure causes limited steam flow to the turbine. Results are similar to LRNBP, but less severe because it takes longer for the MSIVs to close than the turbine control valves. The total MSIV closure and single MSIV closure events show delta-CPR of 0.00 and 0.09 respectively, as shown in PUSAR Table 2.8-12, and, therefore, these events are well bounded by the LRNBP event.

The NRC staff observed that the delta-CPR of the total MSIV closure event is less than the delta-CPR for single MSIV closure event. This is because the total MSIV closure event results in a direct reactor scram. The scram occurs in 3 seconds, shutting down the core before any appreciable pressurization occurs. For the single MSIV closure event, no direct scram signal is generated and, therefore, the scram is delayed until either the reactor high pressure or high neutron flux setting is reached. Thus, the pressurization transient associated with the single

MSIV closure event is permitted to continue, unmitigated, for longer than the total MSIV closure, causing the results for the single MSIV closure event to be more severe. Based on its evaluation, the NRC staff concluded that it is acceptable for the total MSIV closure event to result in a delta-CPR that is less than the delta-CPR of the single MSIV closure case.

Per ELTR1, the PRFD event [[

]] As stated in SRP 15.2.1-5, the small pressure and power changes make PRFD a non-limiting event. [[
]]

The LOCV event is [[
]]

The licensee analyzed the events in this category using the NRC-approved code ODYN, as indicated in PUSAR Table 1-1.

Since the analyses, which were performed in accordance with NRC-approved methodology, showed that the plant performed acceptably under the limiting reduction in secondary heat removal events, the NRC concluded that draft GDCs 6 and 29 are met, and, therefore, this group of transients is acceptable. A summary of the events and associated dispositions from PUSAR Section 2.8.5.2.1 is given in the tables below.

FUEL THERMAL MARGIN EVENTS	DISPOSITION
Generator Load Rejection with Steam Bypass Failure (LRNBP)	[[ ]]
Turbine Trip with Steam Bypass Failure (TTNBP)	[[ ]]
Main Steam Isolation Valve Closure with Direct Scram - with All Valves, with One Valve	[[ ]]
Pressure Regulator Failure Downscale (PRFD)	[[ ]]
Loss of Condenser Vacuum (LOCV)	[[ ]]

TRANSIENT OVERPRESSURE EVENTS	DISPOSITION
Main Steam Isolation Valve Closure with Scram on High Flux (MSIVF)	[[ ]]
Turbine Trip with Bypass Failure and Scram on High Flux (TTNBPF)	]]

Furthermore, the licensee stated that the limiting events in this category will be analyzed on a cycle-specific basis in accordance with the NRC-approved reload safety analysis methodology. Since the effects of these events will be confirmed on a cycle-specific basis, the NRC staff concluded that the licensee's disposition was acceptable.

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 draft GDCs 6 and 29 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 Non-Emergency AC Power to the Station Auxiliaries

Regulatory Evaluation

The loss of non-emergency AC power is assumed to result in the loss of all power to the station auxiliaries and the simultaneous tripping of all reactor coolant circulation pumps. This causes a flow coastdown, as well as a decrease in heat removal by the secondary system, a turbine trip, an increase in pressure and temperature of the coolant, and a reactor trip. Reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered: (1) the sequence of events; (2) the analytical model used for analyses; (3) the values of parameters used in the analytical model; and (4) the results of the transient analyses. The NRC's acceptance criteria are based on: (1) draft GDC-6, insofar as it requires that the reactor core be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits; (2) draft GDC-29, insofar as it requires that a reactivity control system be provided capable of preventing exceeding acceptable fuel damage limits. 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: (1) all external grid connections are lost; or (2) if faults occur in the auxiliary power system itself. When a loss of AC power occurs, all of the recirculation pumps are tripped simultaneously resulting in a flow coastdown and a decrease in heat removal of the secondary system. Loss of Non-emergency AC Power is not included in [[ ]], which lists the transients that are to be addressed in a power uprate submittal. Since it is not included in [[ ]] This event is not analyzed for PBAPS EPU.

[[ ]]

Along with [[ ]], loss of non-emergency AC power event is also bounded by LRNBP. In the scenario of this transient which results from loss of all grid connections, a generator load rejection occurs along with fast closure of the turbine control valves at the beginning of the transient similar to LRNBP. LRNBP is addressed in Section 2.8.5.2.1 of this SE and is acceptable. In addition, no increase in neutron flux occurs during a loss of non-emergency AC power event due to the recirculation pumps trip. Therefore, this event is well bounded by other transients.

Conclusion

The NRC staff has reviewed the licensee's analyses of the loss of non-emergency 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 draft GDCs 6 and 29 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the loss of non-emergency AC power to station auxiliaries event.

2.8.5.2.3 Loss of Normal Feedwater Flow

Regulatory Evaluation

A loss of normal feedwater flow could occur from pump failures, valve malfunctions, or a LOOP. Loss of feedwater flow results in an increase in reactor coolant temperature and pressure, which eventually requires a reactor trip to prevent fuel damage. Decay heat must be transferred from fuel following a loss of normal feedwater flow. Reactor protection and safety systems are actuated to provide this function and mitigate other aspects of the transient. The NRC staff's review covered: (1) the sequence of events; (2) the analytical model used for analyses; (3) the values of parameters used in the analytical model; and (4) the results of the transient analyses. The NRC's acceptance criteria are based on: (1) draft GDC-6, insofar as it requires that the reactor core be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits; (2) draft GDC-29, insofar as it requires that a reactivity control system be capable of preventing exceeding acceptable fuel damage limits. Specific review criteria are contained in SRP Section 15.2.7 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

Higher decay heat results in a more severe reduction in water level for loss of water level events. For the LOFW event, adequate transient core cooling is provided by maintaining the water level inside the core shroud above the top of active fuel (TAF). A plant-specific analysis was performed for PBAPS at EPU conditions. This analysis assumed failure of the HPCI system and used only the RCIC system to restore the reactor water level. RCIC is used because it is the smaller high pressure coolant supply system making the results more limiting than using the HPCI system.

The higher core power levels associated with power uprate will result in more boiloff and a lower water level in the reactor vessel, increasing the potential for core uncovery. The RCIC system should provide sufficient makeup, such that the reactor core remains covered with water until stable conditions are achieved. Because of the extra decay heat from the EPU, slightly more time is required for the automatic systems to restore water level.

The SAFER04 computer code was used for this transient analysis. SAFER is NRC-approved for use in ECCS-LOCA analyses. The use of SAFER in the analysis of LOFW events is specified in Section E.2.3 of ELTR1, which is approved by the staff.

Assumptions for the event are: (1) the reactor is assumed to be at 102% of the EPU power level when the LOFW occurs; (2) the initial level in the model is set at the low-level scram setpoint; (3) reactor feedwater is isolated at event initiation; (4) scram is initiated at the start of the event; and (5) the RCIC system is initiated when the level decreases to the low-low level setpoint. The LOFW analysis assumed a decay heat level of ANS 5.1-1979 with a two-sigma uncertainty, as specified in CLTR. The assumed decay heat level for the EPU analysis was ANS 5.1-1979 decay heat +10 percent, which bounds ANS 5.1-1979 + two sigma. Thus, the key analytical assumptions are the same or conservative relative to the current licensing basis.

The results of the LOFW analysis (Figure 2.8-24 of the PUSAR) for PBAPS show that the minimum water level inside the shroud is 129 inches above the TAF at EPU conditions. The RCIC flow to the vessel begins at 68 seconds into the event; minimum level is reached at 1273 seconds and level is recovered after that point. After the water level is restored, the operator manually controls the water level, reduces reactor pressure, and initiates RHR shutdown cooling. This sequence of events does not require any new operator actions or shorter operator response times.

This LOFW analysis is performed to demonstrate acceptable RCIC system performance. The design-basis criterion for the RCIC system is confirmed by demonstrating that it is capable of maintaining the water level inside the shroud above the TAF during the LOFW transient. Analysis shows that the minimum level is maintained at least 129 inches above the TAF, thereby demonstrating acceptable RCIC system performance. Based on the level recovery and RCIC performance, the NRC staff finds this transient is acceptable under EPU condition.

As discussed in Section 2.8.4.3, an operational requirement is that the RCIC system restores the reactor water level while avoiding ADS timer initiation and main steam isolation valve closure (MSIVC) activation functions associated with the low-low-low reactor water level setpoint (Level 1). This requirement is intended to avoid unnecessary initiations of safety systems. This requirement is not a safety-related function. The results of the LOFW analysis for PBAPS show that the nominal Level 1 setpoint trip is avoided.

Loss of One Feedwater Pump

The Loss of One Feedwater Pump event only addresses operational considerations to avoid reactor scram on low reactor water level (Level 3). This requirement is intended to avoid unnecessary reactor shutdowns. Per Section 4.5 of ELTR2, "[a] plant-specific analysis of the loss of one feedwater pump event will be submitted per Appendix E of ELTR1 to assess the effect of a higher flow control line on scram avoidance." For the PBAPS EPU, the MELLLA region is extended along the existing upper boundary for RTP to the EPU RTP. The PBAPS EPU does not result in a higher flow control line; therefore, a Loss of One Feedwater Pump was not specifically analyzed for EPU.

FUEL THERMAL MARGIN EVENTS	DISPOSITION
Loss of Feedwater (LOFW)	[[ ]]
Loss of One Feedwater Pump	[[ ]]

Conclusion

The NRC staff has reviewed the licensee's analyses of the loss of normal feedwater flow event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of the loss of normal feedwater flow. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of draft GDCs 6 and 29 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the loss of normal feedwater flow event.

2.8.5.3 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 reactor protection system; (6) operator actions; and (7) the results of the transient analyses. The NRC's acceptance criteria are based on: (1) draft GDC-6, insofar as it requires that the reactor core be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits; (2) draft GDC-29, insofar as it requires that a reactivity control system be provided capable of preventing exceeding acceptable fuel damage limits. Specific review criteria are contained in SRP Section 15.3.1-2 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

The loss of forced reactor coolant flow event, including the trip of pump motor and flow controller malfunction events, results in a decrease in reactor core coolant flow rate. As the core flow decreases, additional core void will form and cause a decrease in reactor power through void feedback. 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. Although the licensee intends to install a recirculation pump adjustable speed drive (ASD) in the future, the licensee indicated in Supplement 9 to the EPU LAR (Reference 10) that the proposed EPU does not rely on the ASD modification.

[[

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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 draft GDCs 6, and 29 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 turbine trip. The sudden decrease in core coolant flow while the reactor is at power results in a degradation of core heat transfer, which could result in fuel damage. The initial rate of reduction of coolant flow is greater for the rotor seizure event. However, the shaft break event permits a greater reverse flow through the affected loop later during the transient and, therefore, results in a lower core flow rate at that time. In either case, reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered: (1) the postulated initial and long-term core and reactor conditions; (2) the methods of thermal and hydraulic analyses; (3) the sequence of events; (4) the assumed reactions of reactor system components; (5) the functional and operational characteristics of the reactor protection system; (6) operator actions; and (7) the results of the transient analyses. The NRC's acceptance criteria are based on: (1) draft GDC-32, insofar as it requires that limits, which include considerable margin, be placed on the maximum reactivity worth of control rods or elements and on rates at which reactivity can be increased to ensure that the potential effects of a sudden or large change of reactivity cannot (a) rupture the reactor coolant pressure boundary or (b) disrupt the core, its support structures, or other vessel internals sufficiently to impair the effectiveness of emergency core cooling; and (2) draft GDCs 33, 34, and 35, insofar as they require 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 rapidly propagating fractures is minimized. Specific review criteria are contained in SRP Section 15.3.3-4 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

Increased voids in the core during normal uprated power operation require a slight increase in the recirculation drive flow to achieve the same core flow. Recirculating pump rotor seizure and shaft break are DBAs. Flow through the affected loop is rapidly reduced, leading to a reactor and turbine trip. The sudden decrease in core flow causes a reduction of core heat transfer. However, core uncovery is not expected during this accident.

[[

]]. The licensee states in the PUSAR that events in this category, [[

]] Section 14.5.5.4 of the FSAR, "Recirculation Pump Seizures," discusses that the pump seizure event for single loop operation (SLO) provides a greater challenge to SLMCPR than pump seizure from two loop operation. The FSAR further discusses that some fuel types may require the OLMCPR to be adjusted to ensure a pump seizure event does not cause the SLMCPR to be exceeded while in SLO. [[

]] Therefore, the Reactor Recirculation Pump Rotor Seizure event is not analyzed for EPU.

The NRC staff confirmed, by reviewing TS LCO 3.4.1, that the licensee must adhere to SLO limits for APLHGR, MCPR, and LHGR, and that the APRM high flux trip setpoint must be reduced proportionally to the recirculation flow mismatch for single loop operation.

Based on its review, the NRC staff determined that the rotor seizure/shaft break event remains non-limiting at EPU conditions. PBAPS will continue to adhere to SLO power distribution and MCPR limits to assure that the SLO pump seizure event remains non-limiting. Therefore, the NRC staff concluded that PBAPS RCPB is designed with sufficient margin for this non-limiting event and is equipped with effective reactivity control systems. Therefore, draft GDCs 32, 33, 34, and 35 are satisfied in terms of pressurization, temperature and reactivity changes.

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 nonbrittle manner, the probability of propagating fracture of the RCPB is minimized, and adequate core cooling will be provided. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of draft GDCs 32, 33, 34, and 35 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the sudden decrease in core coolant flow events.

2.8.5.4 Reactivity and Power Distribution Anomalies

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

Regulatory Evaluation

An uncontrolled control rod assembly withdrawal from subcritical or low power startup conditions may be caused by a malfunction of the reactor control or rod control systems. This withdrawal will uncontrollably add positive reactivity to the reactor core, resulting in a power excursion. The NRC staff's review covered: (1) the description of the causes of the transient and the transient itself; (2) the initial conditions; (3) the values of reactor parameters used in the analysis; (4) the analytical methods and computer codes used; and (5) the results of the transient analyses. The NRC's acceptance criteria are based on: (1) draft GDC-6, insofar as it requires that the reactor core be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits; (2) draft GDCs 14 and 15, insofar as they require that the core protection systems be designed to act automatically to prevent or suppress conditions that could result in exceeding acceptable fuel damage limits and that protection systems be provided for sensing accident situations and initiating the operation of necessary ESFs; and (3) draft GDC-31, insofar as it requires that the reactivity control systems be capable of sustaining any single malfunction without causing a reactivity transient, which could result in exceeding acceptable fuel damage limits. Specific review criteria are contained in SRP Section 15.4.1 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

The uncontrolled control rod assembly withdrawal from a subcritical or low power startup condition is not analyzed on a cycle-specific basis. The current licensing basis disposition for this event is based on the rod worth minimizer (RWM), and the use of the banked position withdrawal sequence (BPWS) (PBAPS UFSAR Section 14.5.3.2, "Continuous Rod Withdrawal During Reactor Startup"). Because the BPWS requires rod pull sequences that ensure no control rod has excessive worth, and because the RWM ensures that control rods are withdrawn in-sequence, there is a very low probability that a control rod assembly withdrawal error could occur from a subcritical or low-power startup condition.

In PUSAR Section 2.8.5.4.1, the licensee refers to the CLTR for a disposition for this event. The CLTR (Section 5.1.2) is consistent with the PBAPS licensing basis in that the disposition credits the RWM for ensuring that low-worth rod patterns are enforced "until reactor power has reached appropriate power levels." The CLTR does note that, "[t]he increase in power level could change the power level at which rod patterns are enforced by the RWM..." but concludes that further additional information is not required.

The licensee also provided an additional evaluation of the consequences of a low-power rod withdrawal error in Section 2.8.5.4.1 of the PUSAR. The additional evaluation is based on NEDO-23842, "Continuous Control Rod Withdrawal Transient in the Startup Range." The results of the evaluation, the peak fuel enthalpy, are multiplied by 1.2 to provide an additional margin for the increase in power. The results remain within the acceptance criterion, 170 calories per gram (cal/gm), with significant margin.

The NRC staff reviewed the licensee's disposition and concluded that it was consistent with the CLTR and hence acceptable. In addition, the NRC staff reviewed the PBAPS UFSAR and observed that a PBAPS-specific analysis for this event indicated results that were significantly less severe than the bounding analysis described in NEDO-23842, confirming that the results are applicable to PBAPS. Based on the licensee's evaluation, the NRC staff determined that the results of the low-power control rod withdrawal error remain acceptable for PBAPS at EPU conditions.

Conclusion

The NRC staff has reviewed the licensee's analyses of the uncontrolled control rod assembly withdrawal from a subcritical or low power startup condition and concludes that the licensee's analyses have adequately accounted for the changes in core design necessary for operation of the plant at the proposed power level. The NRC staff also concludes that the licensee's analyses were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure the SAFDLs are not exceeded. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of draft GDCs 6, 14, 15, and 31 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) draft GDC-6, insofar as it requires that the reactor core be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits; (2) draft GDCs 14 and 15, insofar as they require that the core protection systems be designed to act automatically to prevent or suppress conditions that could result in exceeding acceptable fuel damage limits and that protection systems be provided for sensing accident situations and initiating the operation of necessary ESFs; and (3) draft GDC-31, insofar as it requires that the reactivity control systems be capable of sustaining any single malfunction without causing a reactivity transient which could result in exceeding acceptable fuel damage limits. Specific review criteria are contained in SRP Section 15.4.2 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

The at-power rod withdrawal error (RWE) transient is discussed in PBAPS UFSAR Section 14.5.3.1, "Continuous Rod Withdrawal During Power Range Operation." Per the UFSAR, "Control rod withdrawal errors are considered over the entire power range from any normally expected rod pattern. The continuous withdrawal, from any normal rod pattern, of the maximum worth rod results in a moderate core transient mitigated by the action of the Rod Block Monitor."

An RWE event is a localized transient, with reactivity effects focused on the bundles near the erroneously withdrawn control rod. Therefore, since the licensee is using GNF2 fuel, the ELTR1 disposition for the RWE is necessary. The licensee states that the event was analyzed for EPU effects, in accordance with GESTAR II, using PANACEA. The results of the analysis are provided in Table 2.8-12 of the PUSAR. The uncorrected EPU ΔCPR value is 0.27.

The RWE is within the PBAPS reload evaluation scope, meaning that it is analyzed on a cycle-specific basis in accordance with the NRC-approved reload safety analysis methods. On a cycle-by-cycle basis, this value will be analyzed and used, if limiting, to establish the OLMCPR.

Since the licensee has quantified the impact of the EPU RWE, and because the RWE is analyzed on a cycle-specific basis in accordance with NRC-approved reload safety analysis methods, the NRC determined that the proposed EPU is acceptable with respect to the RWE event.

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 draft GDCs 6, 14, 15, and 31 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. 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) draft GDC-6, insofar as it requires that the reactor core be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits; (2) draft GDCs 14 and 15, insofar as they require that the core protection systems be designed to act automatically to prevent or suppress conditions that could result in exceeding acceptable fuel damage limits and that protection systems be provided for sensing accident situations and initiating the operation of necessary ESFs; (3) draft GDC-32, insofar as it requires that limits, which include considerable margin, be placed on the maximum reactivity worth of control rods or elements and on rates at which reactivity can be increased to ensure that the potential effects of a sudden or large change of reactivity cannot (a) rupture the reactor coolant pressure boundary or (b) disrupt the core, its support structures, or other vessel internals sufficiently to impair the effectiveness of emergency core cooling; and (4) draft GDC-29, insofar as it requires that at least one of the reactivity control systems be capable of making the core subcritical under any condition sufficiently fast to prevent exceeding acceptable fuel damage limits. Specific review criteria are contained in SRP Section 15.4.4-5 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

A number of AOOs may cause either increased core flow or introduction of cooler water into the core. These AOOs result in an increase in core reactivity due to decreased moderator temperature or core void fraction. The licensee indicated, in PUSAR Table 2.8-12, that the recirculation flow increase transients are not analyzed at CLTP conditions; however, both events are considered for EPU.

Two recirculation flow control events are considered: a slow recirculation flow increase, and a fast recirculation flow increase. The licensee stated, in PUSAR Section 2.8.5.4.3, that [[

]]

The NRC staff confirmed the licensee's disposition for the fast recirculation flow increase by reviewing GESTAR-II, "General Electric Standard Application for Reactor Fuel," Supplement for United States, Appendix C, Chapter 6 (Reference 67). The information contained in GESTAR-II is consistent with the information provided by the licensee. In addition, the licensee provided the results of a fast recirculation flow increase event at EPU conditions, considering both the existing recirculation pump motor-generator sets, and the proposed adjustable speed drive modification. The results of both provided further confirmation that this event is non-limiting.

The NRC staff determined that licensee's disposition for the slow recirculation increase is acceptable because the licensee's statement means that the power uprate does not affect the initial conditions for the event. The licensee applies MCPR multipliers ($MCPR_f$) at less-than-rated conditions to ensure there is adequate thermal margin to accommodate the consequences of this event. Furthermore, Chapter 9.1.2 of the CLTR states, [[

]]

The licensee also evaluated the idle recirculation pump start event. The licensee stated that this event is [[

]] The NRC staff confirmed that [[

]], meaning that it need not be analyzed for EPU.

Based on the evaluation described above, the NRC staff concluded that the licensee has acceptably evaluated the effects of the recirculation flow increase transients. The licensee has identified the limiting initiating events in this category, and provided an acceptable analytical

disposition for the limiting events. In addition, [[
]]

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 draft GDCs 6, 14, 15, 29, and 32 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 control rod drop accident 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 draft GDC-32, insofar as it requires that limits, which include considerable margin, be placed on the maximum reactivity worth of control rods or elements and on rates at which reactivity can be increased to ensure that the potential effects of a sudden or large change of reactivity cannot (a) rupture the reactor coolant pressure boundary, or (b) disrupt the core, its support structures, or other vessel internals sufficiently to impair the effectiveness of emergency core cooling. Specific review criteria are contained in SRP Section 15.4.9 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

The control rod drop accident (CRDA) is analyzed as described in Section 14.6.2 of the PBAPS UFSAR. The event assumes that a fully inserted control rod becomes uncoupled from its drive and rapidly falls out of the core. Several possible initiating events are summarized in the UFSAR. The rate of positive reactivity insertion is bounding of the maximum control rod drop velocity, which is limited by the control rod velocity limiter. Neutron flux increases and fuels are heated up. Eventually high neutron flux trips the reactor protection system and the reactor scrams. Prior to trip, the severity of the transient is limited by the Doppler coefficient, which limits the flux increase as the fuel heats.

The licensee stated the following in USAR Section 2.8.5.4.4 regarding the CRDA at EPU conditions for PBAPS:

- The spectrum of CRDAs does not change with EPU.

- The PBAPS CRDA analysis is based on NEDO-21231, "Banked Position Withdrawal Sequence," dated January 1977 (ADAMS Accession No. ML090771242, non-publicly available).

- The reactor control system (i.e., rod worth minimizer and rod control information system) provides the same level of protection for the fuel following EPU.

- Despite that no change in peak fuel enthalpy is expected at EPU conditions, multiplying the CLTP peak fuel rod enthalpy by 1.2 still produces a result that, at 162 cal/gram, remains well within the 280 cal/gram acceptance criterion.

Based on NEDO-21231, the 280 cal/gram acceptance criterion is applied to ensure that the core remains in a coolable geometry. According to SRP Section 4.2, "Fuel System Design," Appendix B, "Interim Acceptance Criteria and Guidance for the Reactivity Initiated Accidents," a more restrictive value of 230 cal/gram is used for core coolability. Although the NRC staff is not imposing the more restrictive acceptance criterion on PBAPS, it is noteworthy that the EPU-scaled peak enthalpy remains below this value, as well. Further, NEDO-21231 indicates that a peak enthalpy value of 170 cal/gram may be used as an acceptance criterion for fuel cladding failure. While the EPU evaluation concludes that the peak enthalpy remains below this value, a separate radiological consequences evaluation addresses the effects of potential fuel cladding failure. The radiological consequences of this event associated with fuel cladding failure are evaluated in Section 2.9.2 of this SE.

The NRC staff determined that the licensee's evaluation acceptably accounted for the effects of the proposed EPU for the following reasons: (1) the licensee will continue to adhere to the BPWS, which limits the worth of any one control rod; (2) the rate of reactivity insertion is additionally constrained by the velocity limiter; and (3) the licensee conservatively estimated the peak fuel enthalpy by scaling a pre-EPU result to account for the possibility of increased control blade worth. The results show that the fuel will remain in a coolable geometry following a postulated CRDA.

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 draft GDC-32 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 overpressurization of the RCS. Alternatively, a power level decrease and depressurization may result. Reactor protection and safety systems are actuated to mitigate these events. The NRC staff's review covered: (1) the sequence of events; (2) the analytical model used for analyses; (3) the values of parameters used in the analytical model; and (4) the results of the transient analyses. The NRC's acceptance criteria are based on: (1) draft GDC-6, insofar as it requires that the reactor core be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits; and (2) draft GDC 29, insofar as it requires that at least one of the reactivity control systems be capable of making the core subcritical under any condition sufficiently fast to prevent exceeding acceptable fuel damage limits. Specific review criteria are contained in SRP Section 15.5.1-2 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

Several systems are available for providing high pressure supplies of cold water to the vessel for normal or emergency functions. This event causes a possibility of high water level and an increase in power due to higher core inlet subcooling. The severity of the resulting transient is highest for the largest of these abnormal events: the inadvertent startup of the HPCI system.

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As seen in Table 1-1 of the PUSAR, the inadvertent operation of the HPCI System event is analyzed using the NRC-approved code ODYN.

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The licensee's evaluation demonstrates that the SAFDLs are met; hence, the NRC staff determined that 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 draft GDCs 6 and 29 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 feedwater control system using water from the condensate storage tank 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) draft GDC-6, insofar as it requires that the reactor core be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits; and (2) draft GDC-29, insofar as it requires that a reactivity control system be provided capable of preventing exceeding acceptable fuel damage limits. Specific review criteria are contained in SRP Section 15.6.1 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

As discussed in UFSAR Section 14.5.4.2, 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 turbine control valves far enough to maintain constant reactor vessel pressure. Reactor power settles out at nearly the initial power level. This event will have only a slight effect on fuel thermal margins. The change in fuel rod surface heat flux is expected to be negligible, causing an insignificant change in the MCPR. Thus, this transient is bounded by more severe transients. As such, as discussed in PUSAR Section 2.8.5.6.1, consistent with ELTR1, this transient [[ ]]

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 draft GDCs 6 and 29 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, 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) draft GDCs 40 and 42, insofar as they require that protection be provided for ESFs against the dynamic effects that might result from plant equipment failures, as well as the effects of a LOCA; and (4) draft GDCs 37, 41, and 44, insofar as they require that a system to provide abundant emergency core cooling be provided so that fuel and clad damage that would interfere with the emergency core cooling function 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 emergency core cooling system (ECCS) for PBAPS is described in Chapter 6, "Core Standby Cooling Systems," of the PBAPS UFSAR. Its key systems include the high-pressure coolant injection (HPCI), core spray (CS), low pressure coolant injection (LPCI), and automatic depressurization system (ADS). The HPCI system is a lower capacity, turbine driven makeup system that can inject coolant at high pressures in order to alleviate coolant inventory loss due to a small pipe break, which may not depressurize the RCS to the cut-in pressure for the lower pressure ECCS. The ADS is a control system that opens five safety/relief valves to depressurize the RCS following a small break, so that the low pressure ECCS can function to add coolant. The LPCI is an operating mode of the RHR system in which the RHR pumps align and inject emergency core cooling into the downcomer. The CS injects coolant at low pressure into a spray header, to provide spray cooling above the core.

The CLTR provides a disposition for the ECCS equipment, concluding that the ECCS hardware is largely unaffected by an EPU. In Section 2.8.5.6.2 of the PUSAR, the licensee refers to this disposition for the PBAPS ECCS. Since the hardware performance capabilities are inputs to the ECCS evaluation, the NRC determined that the EPU effects are appropriately characterized by the loss-of-coolant accident (LOCA) analyses. Therefore, the NRC staff agrees that the dispositions in the CLTR are appropriate for the PBAPS EPU with respect to the ECCS.

The CLTR also provides a straightforward disposition for the ECCS evaluation for EPU; however, the licensee stated in PUSAR Section 2.8.5.6.2.5 that its use of GNF2 fuel requires reference, instead, to ELTR1. ELTR1 indicates that no significant changes in predicted ECCS performance are expected, but also requires a plant-specific ECCS evaluation to be performed using NRC-approved methods.

The licensee evaluated the effects of the EPU on ECCS performance by performing a LOCA break spectrum analysis using the NRC-approved SAFER/GESTR methodology (NEDE-23785-2-PA, "The GESTR-LOCA and SAFER Models for the Evaluation of the Loss-of-Coolant Accident"). The use of the NRC-approved evaluation model ensures that the licensee has addressed the requirements of ELTR1, and it also ensures that ECCS performance is evaluated using "an acceptable evaluation model," pursuant to the requirements of 10 CFR 50.46(a)(1)(i).

The SAFER/GESTR methodology conforms to the required and acceptable features of ECCS evaluation models set forth in Appendix K to 10 CFR Part 50. The methodology was developed in accordance with the framework established in SECY 83-472, "Emergency Core Cooling System Analysis Methods," dated November 17, 1983.

The effects of the EPU are analyzed in a series of [[ ]] cases, which span power shapes and break sizes and locations as discussed in Attachment 5 to Supplement 1 to the EPU LAR (Reference 2). These cases are analyzed assuming [[

]] This set of analyses shows that the licensee has calculated ECCS performance for a number of LOCAs "of different sizes, locations, and other properties sufficient to provide assurance that the most severe postulated loss-of-coolant accidents are calculated," pursuant to 10 CFR 50.46(a)(1)(i).

A condition for the use of GEH analytic methods for expanded operating domains, including EPU, requires that both top-peaked and mid-peaked axial power shapes be considered in ECCS evaluations; the licensee's statements in the PUSAR and in the supplemental analysis confirm that this condition has been satisfied. Satisfying this interim methods condition addresses the "other properties" clause of 10 CFR 50.46(a)(1)(i).

The licensee's break spectrum analysis reveals that there are two limiting transients. The first is the limiting large-break, and the second is the limiting small-break. Of the two, the small break yields the highest predicted peak cladding temperature.

Large Break

The licensee concluded in PUSAR Section 2.8.5.6.2.5.1 that, "the large break PCT [peak cladding temperature] results increased slightly as a result of the LPCI flow reduction but were significantly less than the limiting small break PCT results." Supplement 1 to the EPU LAR provides additional detail regarding the ECCS evaluation. [[

]], the fuel cladding heatup is reasonably driven by stored energy in the fuel in addition to the decay heat. In consideration of the transient behavior, the conclusion that the EPU does not significantly affect large break performance is reasonable, because the characteristics of the high-powered bundle do not change.

The licensee provided the results of the EPU large break cases considering both normal and reduced LPCI flows. [[

]] Given the reduction in LPCI flow, a higher large break PCT is expected and this result is acceptable.

Small Break

PBAPS is a small-break limited plant at the CLTP condition. This remains the case for the EPU. Since the small break sequence of events evolves over a longer period of time, the decay heat becomes more significant than the stored energy in determining the characteristics of the fuel cladding heatup. Since the decay heat load is higher at EPU conditions, the small break PCT increases. As shown in Supplement 1 to the EPU LAR, the licensee's break spectrum analysis confirms that the limiting break size has been identified, and that the ADS remains adequate to depressurize the RCS to the LPCI and LPCS cut-in pressures. The low pressure ECCS provides cooling to refill the core and terminate the cladding heatup.

The PCT reaches approximately [[ ]], which is less than the 2200 °F acceptance criterion set forth in 10 CFR 50.46(b)(1), and is acceptable. Based on this result, the licensee determined that the licensing basis PCT for EPU is 1925 °F.

Thermal Conductivity Degradation

In Supplement 2 to the EPU LAR (Reference 3), the licensee provided updated results for the limiting large- and small-break LOCA analyses using the SAFER/PRIME model. Unlike GESTR-LOCA, the PRIME fuel performance code includes models that account for the burnup-dependent degradation of nuclear fuel thermal conductivity (thermal conductivity degradation, (TCD)). The licensee concluded that the PRIME-based analysis showed that TCD had an insignificant effect on the results of the analysis. The licensee's updated results, which included core wide and local oxidation results, showed that [[

]] The NRC staff considers this result acceptable, because degraded TCD causes the initial stored energy in the fuel to increase, a phenomenon that is more significant in the large break, [[

]] The discussion on results, below, provides the updated evaluation results based on the use of the PRIME-based evaluation.

Results

The table below provides the pre-EPU and post-EPU predicted PCTs for the limiting breaks based on PUSAR Table 2.8-6:

Break Size	CLTP	EPU
Large Break	[[ ]]	[[ ]]
Small Break	[[ ]]	[[ ]]

Per the table above, the limiting results are below the 2200 °F acceptance criterion set forth in 10 CFR 50.46(b)(1).

For all break sizes discussed in the PUSAR, the predicted cladding oxidation remains below 4% original cladding thickness, and the hydrogen generation accounts for less than 0.1% of core-wide metal water reaction. These results remain within the 10 CFR 50.46(b)(2) and (b)(3) acceptance criteria of 17% and 1%, respectively.

The updated results reflecting consideration of TCD, based on Supplement 2 to the EPU LAR, are as follows:

Break Size	Parameter	Value
Large Break	PCT	[[ ]]
	Hydrogen Generation	[[ ]]
	Local Oxidation	[[ ]]
Small Break	PCT	[[ ]]
	Hydrogen Generation	[[ ]]
	Local Oxidation	[[ ]]

The updated results remain within the 10 CFR 50.46(b) acceptance criteria, and the PRIME fuel performance model is NRC-approved. Based on these considerations, the NRC staff determined that the updated results are acceptable.

On a cycle-specific basis, the licensee evaluates the MCPR, MAPLHGR, and LHGR limits and confirms their applicability with respect to the ECCS-LOCA analysis. This evaluation is performed in accordance with the NRC-approved reload evaluation method.

Coolable Geometry and Long-Term Core Cooling

The acceptance criteria at 10 CFR 50.46(b)(4) and (b)(5) require that the core remain in a coolable geometry, and that long-term core cooling be provided, following a LOCA. The licensee stated in PUSAR Section 2.8.5.6.2.5.5 that conformance to 10 CFR 50.46(b)(4) is demonstrated because the cladding temperature and local oxidation values remain within the acceptance criteria. For long-term core cooling, the licensee stated in PUSAR Section 2.8.5.6.2.5.6, that long-term core cooling is assured by either: (1) core can be reflooded above top of active fuel; or (2) core can be reflooded to the elevation of the jet pump suction and one core spray system can be placed in operation at rated flow. Based on its review of the licensee's ECCS evaluation results, the NRC staff determined that the licensee's results show conformance to the PCT and cladding oxidation criteria, and that following the limiting small break LOCA, the water level is recovered to the top of active fuel based, in part, on core spray operation. The NRC staff, therefore, concluded that the licensee's disposition for 10 CFR 50.46(b)(4) and (b)(5) was acceptable with respect to the requested EPU.

Based on the licensee's plant-specific LOCA analysis for PBAPS EPU, and because the licensee will perform cycle-specific evaluations of ECCS performance, the NRC staff determined that the licensee's EPU evaluation for ECCS performance was acceptable. The staff's conclusion is based on the following considerations:

- The licensee's evaluation was performed for the entire EPU break spectrum.
- The analysis was performed using the NRC-approved SAFER/GESTR LOCA methodology.
- The results conform to the acceptance criteria set forth in 10 CFR 50.46(b).
- The licensee will confirm the applicability of the analysis on a cycle-specific basis.

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 reactor protection system and the ECCS will continue to ensure that the peak cladding temperature, 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 draft GDCs 37, 40, 41, 42, and 44, 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 draft GDCs 14 and 15. The regulations in 10 CFR 50.62 requires, in part, that:

- each BWR have an alternate rod injection (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 standby liquid control (SLC) system 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 inside diameter reactor vessel.
- 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 SLC system pump discharge relief valve such that SLC system operability is not affected by the proposed EPU; and (3) operator actions specified in the plant's Emergency Operating Procedures 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 followed by failure of a reactor scram. Due to strong reactivity feedback from this event, reactor power and pressure rise rapidly to reach maximum values and challenge the RCPB and thermal design limits. Eventually, the SLC system will inject boron solution into the core after the first SRV opens to relieve reactor pressure. This brings the reactor to a subcritical state. Subcriticality is sustained until the reactor cools down to the cold-shutdown condition.

The licensee states in Section 2.8.5.7 of the PUSAR that PBAPS 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 of 13 weight percent natural boron; and (3) an automatic ATWS-recirculating pump trip (RPT) logic has been installed. Section L.3 of ELTR1 discusses ATWS analyses and provides a generic evaluation guideline 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) loss-of-offsite power (LOOP); and (4) inadvertent opening of a relief valve. The licensee reviewed the results of the ATWS analyses considering the limiting cases for RPV overpressure, suppression pool temperature, and containment pressure. Previous evaluations completed by the licensee considered the four ATWS events listed in Section L.3 of ELTR1. Based on past experience and generic analyses performed as part of ELTR2, two of the four cases needed to be further analyzed for PBAPS EPU: (1) MSIVC; and (2) PRFO. For PBAPS, a LOOP does not result in a reduction in the RHR pool cooling capability relative to these cases. Thus, with the same RHR pool cooling capability, the containment responses for the MSIVC and PRFO cases bound the LOOP case.

The results of the analyzed events are evaluated in the sections below. The EPU ATWS analyses were performed with a GNF2 equilibrium core using the NRC-approved computer code ODYN. The input parameters for PBAPS ATWS were provided in Table 2.8-7 of the PUSAR. The results of the analysis are provided in Table 2.8-8 of the PUSAR as supplemented by the information in Section 4.0 of Attachment 1 to Supplement 27 to the EPU LAR (Reference 116). The potential for thermal-hydraulic instability in conjunction with ATWS events is discussed in Section 2.8.3.2 of the PUSAR, and is evaluated in Section 2.8.3 of this SE.

The licensee states in the PUSAR that there are changes to the assumed operator actions for the EPU ATWS analysis. The changes are required to supplement the CST volume from the RWST in a certain timeframe after the start of an ATWS event. BWROG "Emergency Procedure and Severe Accident Guidelines (EPGs/SAGs)," Revision 2, March 2001, is currently implemented at PBAPS. The NRC staff confirmed the functionality of the SLC system in relation to operator actions based on EOPs for ATWS-RPT during an audit conducted at PBAPS on November 8, 2013 (Reference 85).

For every reload, the licensee screens plant modifications, changes in fuel design, and other reactor operating changes to identify if the ATWS analyses could be impacted. This will provide assurance that future operation will continue to meet the ATWS acceptance criteria.

ATWS (Overpressure)

Higher operating steam flow will result in higher peak vessel pressures. The increased core power and reactor steam flow rates, in conjunction with the SRV capacity and response times, can affect the capability of the SLC system to mitigate the consequences of an ATWS event.

The licensee's overpressure evaluation included a review of the results of the analyses of ATWS events to identify the most limiting RPV overpressure conditions. Two events, MSIVC and PRFO, were further analyzed for PBAPS. The limiting ATWS event with respect to RPV overpressure for PBAPS is PRFO. The PRFO event produces the highest peak lower plenum pressure of 1461 psia (Reference 116).

ATWS (Suppression Pool Temperature)

The increased core power and reactor steam flow rates, in conjunction with the SRV capacity and response times, can affect the capability of the SLC system to mitigate the consequences of an ATWS event. The higher power and decay heat can result in higher suppression pool temperatures.

The licensee's suppression pool temperature evaluation included a review of the results of the analyses of ATWS events to identify the most limiting containment response. Two events, MSIVC and PRFO, were further analyzed for PBAPS. The limiting ATWS event with respect to containment response for PBAPS is PRFO resulting in a peak suppression pool temperature of 168.3 °F. The CLTP suppression pool temperature is 188.4 °F. The main reason for a decrease in suppression pool temperature is associated with the licensee's decision to eliminate CAP credit. CAP credit can be eliminated by decreasing the suppression pool temperature, which can provide better available NPSH margins. The method the licensee has chosen to decrease suppression pool temperature during ATWS is an increase in the isotopic enrichment of B-10 in the SLC fluid (discussed in detail in Section 2.8.4 of this SE). With the isotopic enrichment increase, the SLC system needs to run for a shorter period of time to reach shutdown conditions. This shorter time period causes less energy to be transferred to the coolant, which in turn, causes the SRVs to be open for a shorter period of time. Since the SRVs are open for a shorter period of time, less energy is transferred to the suppression pool; therefore, the suppression pool temperature is lower.

ATWS (Peak Cladding Temperature)

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For ATWS events, the acceptance criteria for PCT and local cladding oxidation for ECCS, defined in 10 CFR 50.46 are adopted to ensure an ATWS event does not impede core cooling. Coolable core geometry is assured by meeting the 2200 °F PCT and the 17 percent local cladding oxidation acceptance criteria stated in 10 CFR 50.46.

The ATWS analyses results demonstrate significant margin to the PCT acceptance criteria of 2200 °F. The MSIVC and PRFO events were analyzed for PBAPS EPU conditions. The highest calculated PCT for ATWS events decreased from 1415 °F at CLTP to 1342 °F at EPU, which resulted from the PRFO event. Local cladding oxidation is not explicitly analyzed because, with PCT less than 1600 °F, cladding oxidation has been demonstrated to be insignificant compared to the acceptance criteria of 17% of cladding thickness. The licensee supplemented this statement in Supplement 9 to the EPU LAR (Reference 10) by illustrating how the Baker-Just zircaloy-water reaction equation is used in the SAFER method (SAFER is the NRC-approved code used by PBAPS for transient analysis). The NRC staff confirmed that cladding oxidation is insignificant when PCT is less than 1600 °F. Therefore, a qualitative evaluation of the local cladding oxidation for the PBAPS ATWS events to demonstrate compliance with the acceptance criteria of 10 CFR 50.46 is acceptable to the staff. As a result, the ATWS analysis is in compliance with the PCT acceptance criteria of 10 CFR 50.46(b).

Summary of the Results

Table 2.8-8 of the PUSAR lists the key results of the ATWS analysis under EPU conditions. The results are summarized as follows:

- Peak vessel bottom pressure is 1461 psig[1], which is less than the ASME Service Level C limit of 1500 psig.
- Peak suppression pool temperature is 168.3 °F, which is less than the design limit of 180 °F.
- Peak containment pressure 8.3 psig, which is less than the design limit of 56 psig.
- Peak cladding temperature is 1342 °F, which is less than the 10 CFR 50.46 limit of 2200 °F.
- Local cladding oxidation is less than the 10 CFR 50.46 limit of 17%.

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1 PUSAR Table 2.8-8 lists the peak vessel bottom pressure for the EPU ATWS analysis as 1458 psig. In an email on May 7, 2014, the licensee indicated that the value was in error and should have been 1461 psig. The revised value of 1461 psig was formally docketed in Section 4.0 of Attachment 1 to EPU LAR Supplement 27 dated June 5, 2014 (Reference 116).

The above results show the ATWS acceptance criteria are satisfied. The results for EPU conditions show a decrease in peak vessel bottom pressure, peak suppression pool temperature, peak containment pressure, and peak cladding temperature when compared to CLTP conditions. This is not intuitive of implementing EPU, as an increase in the results is expected. The decrease in results can be attributed to the licensee's proposal to install an additional SSV on each unit to provide additional overpressure protection for ATWS events. A more thorough discussion of this modification is included in Section 2.8.4 of this SE.

Based on staff evaluation, the NRC staff accepts the ATWS analyses based on the following facts: (1) the ATWS analysis at EPU conditions are based on NRC-approved methods; (2) the results meet the three acceptance criteria defined at 10 CFR 50.62; (3) the EPU implementation has sound operator strategy on ATWS level reduction or early boron injection in the EOP with the BWROG EPGs/SAGs strategy; and (4) the results of the analyses are in compliance with the acceptance criteria of 10 CFR 50.46.

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, SLC system, and recirculation pump trip 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 facilities. The NRC's acceptance criteria are based on final 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

As discussed in PUSAR Section 2.8.6.1, PBAPS has a new fuel storage facility (also referred to as the new fuel storage vault). However, this facility is not used. As described in UFSAR Section 10.2.1, and as required by TS 4.3.1.2, new fuel is stored in the spent fuel pool (SFP). As a result, the NRC staff concludes that no evaluation of the new fuel storage facility is required for the proposed EPU since it is bounded by the review for the SFP described in SE Section 2.8.6.2 below.

Conclusion

The NRC staff has reviewed the proposed EPU with respect to its effect on new fuel storage and has determined that it is bounded by the review for the SFP described in SE Section 2.8.6.2 below.

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) final 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) final 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 PUSAR Section 2.8.6.2, the increased decay heat from EPU results in a higher heat load in the SFP racks during long-term storage. The review of the SFP with respect to heat load is discussed above in SE Section 2.5.3.1.

The PUSAR states that the licensee has evaluated the proposed EPU with respect to criticality analyses. The licensee concluded that analyses demonstrate that the SFP design will continue to ensure an acceptable degree of sub-criticality following implementation of the proposed EPU and that the EPU would not change the licensing basis with respect to SFP storage. The current PBAPS licensing basis with respect to SFP storage includes the criticality requirements in TS 4.3.1.1, and the considerations contained in license condition 2.C(14). The TS and license condition requirements were approved by the NRC in PBAPS, Units 2 and 3, Amendments Nos. 287 and 290 on May 21, 2013 (Reference 86). These amendments approved the use of NETCO-SNAP-IN® neutron absorbing inserts in the SFP storage racks for the purpose of criticality control in the SFPs (one SFP for each unit). The installation of the NETCO-SNAP-IN® rack inserts was undertaken by the licensee to address degradation of the Boraflex neutron absorbing material originally installed in the SFPs. The NRC staff's SE for these amendments concluded that there was reasonable assurance that the fuel storage criticality requirements in GDC-62 and 10 CFR 50.68 will continue to be met following implementation of the amendments. Based on its previous review, with respect to the NETCO-

SNAP-IN® rack inserts, the NRC staff finds the proposed EPU acceptable with respect to spent fuel storage.

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 final 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.

2.9 Source Terms and Radiological Consequences Analyses

The licensee discussed the impact of the proposed EPU with respect to source terms and radiological consequences analyses in Section 2.9 of the PUSAR, with additional information provided in Supplements 3 (Reference 4), and 9 (Reference 10) to the EPU LAR. The NRC staff's review is provided below.

2.9.1 Source Terms for Radwaste Systems Analyses

Regulatory Evaluation

The NRC staff reviewed the radioactive source term associated with EPUs to ensure the adequacy of the sources of radioactivity used by the licensee as input to calculations to verify that the radioactive waste management systems have adequate capacity for the treatment of radioactive liquid and gaseous wastes. The NRC staff's review included the parameters used to determine: (1) the concentration of each radionuclide in the reactor coolant; (2) the fraction of fission product activity released to the reactor coolant; (3) concentrations of all radionuclides other than fission products in the reactor coolant; (4) leakage rates and associated fluid activity of all potentially radioactive water and steam systems; and (5) potential sources of radioactive materials in effluents that are not considered in the plant's UFSAR related to liquid waste management systems and gaseous waste management systems. The NRC's acceptance criteria for source terms are based on: (1) 10 CFR Part 20, insofar as it establishes requirements for radioactivity in liquid and gaseous effluents released to unrestricted areas; (2) 10 CFR Part 50, Appendix I, insofar as it establishes numerical guides for design objectives and limiting conditions for operation to meet the "as low as is reasonably achievable" criterion; and (3) final 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 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, the migration of radionuclides from the fuel, radioactive decay and the removal of radioactive material by coolant purification systems. Radiation sources in the reactor coolant include activation products, activated corrosion products and fission products. During reactor operation, some stable isotopes in the coolant passing through the core become radioactive (activated) as a result of nuclear reactions. For example, the 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. The increase in the activation of the water in the core region is in approximate proportion to the increase in thermal power. Under EPU conditions there is a necessary increase in the steam flow. This increase in steam flow [[

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Another source of activity in the reactor coolant is from the activation of metallic corrosion products contained in the coolant as it passes through the reactor core. Under EPU conditions, there will be an increase in flow and an increase in the activation rate resulting in an increase in the corrosion products present in the reactor coolant. The licensee performed [[ ]] evaluations, using current licensing basis methodologies, to verify that expected coolant concentrations at EPU power levels will be bounded by the current licensing basis values. Since the original design basis uses very conservative assumptions to determine the design basis fission product inventory, the calculated EPU fission product activity levels in the reactor coolant will remain well within the design basis.

<u>Conclusion</u>

The NRC staff has reviewed the radioactive source term associated with the proposed EPU and concludes that the proposed parameters and resultant composition and quantity of radionuclides are appropriate for the evaluation of the radioactive waste management systems. The NRC staff further concludes that the proposed radioactive source term meets the requirements of 10 CFR Part 20, 10 CFR Part 50, Appendix I, and final GDC-60. Therefore, the NRC staff finds the proposed EPU acceptable with respect to source terms.

2.9.2 Radiological Consequences Using Alternative Source Term

<u>Regulatory Evaluation</u>

The licensee reviewed the design-basis accident (DBA) radiological consequences analyses to determine the impact of the EPU. The radiological consequences analyses reviewed were the LOCA, fuel handling accident (FHA), control rod drop accident (CRDA), and main steam line break accident (MSLBA). The licensee'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 staff reviewed the results of the licensee's analyses. The NRC's acceptance criteria for radiological consequences analyses using an alternative source term (AST) are based on: (1) 10 CFR 50.67, insofar as it describes reference values for radiological consequences of a postulated maximum hypothetical accident; (2) Regulatory Guide 1.183, insofar as it describes accident specific dose guidelines for events with a higher probability of occurrence; and (3) final 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

To determine the effect of the EPU on the design basis radiological analyses, the licensee reviewed the following accidents: LOCA, FHA, MSLBA and the CRDA. The current license thermal power (CLTP) dose consequence analyses for these accidents, using an AST, were reviewed and approved by the NRC on September 5, 2008, as documented in PBAPS, Units 2 and 3, License Amendments 269 and 273 (Reference 79, referred to below as the PBAPS AST amendment). The CLTP analyses are based on 3,528 MWt, which corresponds to the CLTP power level of 3,514 MWt with a 0.4% ECCS evaluation uncertainty factor applied. The licensee performed the EPU DBA analyses at 102% of the EPU power level of 3,951 MWt, which equates to 4,030 MWt. The licensee largely maintained consistency with the CLTP analyses with minor changes to input assumptions to reflect the proposed EPU conditions. These changes are described for each accident as evaluated by the NRC staff below. Consistent with NRC regulations and regulatory guidance, the licensee determined the TEDE at the exclusion area boundary (EAB) for the limiting 2-hour period; at the outer boundary of the low population zone (LPZ); and in the control room for the duration of the accident analysis, which is taken as 30 days. The results of the evaluations performed by the licensee, as well as the applicable dose acceptance criteria from RG 1.183 (Reference 54), are shown in Table 2.9.2-1 below.

Meteorological Data

The licensee used 5 years of onsite hourly meteorological data collected during calendar years 1984 through 1988 to generate the atmospheric dispersion factors (χ/Q values) for use in the proposed EPU LAR. These data were included in the licensee's application dated July 13, 2007, (ADAMS Accession No. ML072570156) related to the PBAPS, Units 2 and 3, AST amendment. These data were provided for NRC staff review in the form of hourly meteorological data files for input into the ARCON96 atmospheric dispersion computer code (NUREG/CR-6331, Revision 1, "Atmospheric Relative Concentrations in Building Wakes") and joint frequency distributions for input to the PAVAN atmospheric dispersion computer code (NUREG/CR-2858, "PAVAN: An Atmospheric Dispersion Program for Evaluating Design Basis Accidental Releases of Radiological Materials from Nuclear Power Stations"). The evaluation of the meteorological data is discussed in the staff's SE in support of the PBAPS AST amendment. The NRC staff reviewed the overall quality of the data, found it to be consistent with the guidance outlined in RG 1.23, "Meteorological Monitoring Programs for Nuclear Power Plants," (Reference 80), and therefore, determined that the data were acceptable for use in licensing actions.

Control Room Atmospheric Dispersion Factors

In support of the PBAPS AST amendment, the licensee calculated control room χ/Q values for the LOCA, CRDA, and FHA events using 1984 through 1988 onsite meteorological data and guidance provided in RG 1.194, "Atmospheric Relative Concentrations for Control Room Radiological Habitability Assessment at Nuclear Power Plants" (Reference 81). RG 1.194, states that ARCON96 is an acceptable methodology for assessing control room χ/Q values for use in DBA radiological analyses. The NRC staff evaluated the applicability of the ARCON96 model and concluded that there was no unusual siting, building arrangements, release characterization, source-receptor configuration, meteorological regimes, or terrain conditions that precluded the use of this model in support of the LAR. The licensee did not calculate MSLB control room χ/Q values because the control room dose at the air intake was calculated using steam cloud concentrations rather than χ/Q values. The NRC staff's assessment of the AST control room χ/Q values is discussed in the staff's SE for the PBAPS AST amendment. The NRC staff qualitatively reviewed the inputs and assumptions used for the control room χ/Q value assessment and found them generally consistent with site configuration drawings and staff practice. The staff also reviewed the licensee's assessments of control room post-accident dispersion conditions generated from the licensee's meteorological data and atmospheric dispersion modeling. On the basis of the review, the staff concluded that the χ/Q values were acceptable for use in the AST DBA control room dose assessments. These values became the current licensing basis control room χ/Q values.

In an RAI regarding the proposed EPU LAR, the NRC staff asked the licensee to outline the changes between its current licensing basis and the proposed EPU. In the RAI response dated May 24, 2013 (Reference 4), the licensee noted that while the analysis for the control room χ/Q values for the LOCA remained unchanged, the FHA and CRDA were being extended from a 24-hour accident duration to a 720-hour accident duration. The NRC staff noted that for the AST amendment, the FHA χ/Q values were measured from the following release points: reactor building (RB) stack, RB personnel access door, RB roof scuttle, railroad bay door and ground level hatch release. For the EPU, the licensee lists the FHA current licensing basis release location as the Unit 2 roof scuttle, and calculates the extended accident duration for the FHA from this release point.

The licensee used the same meteorological data, inputs, and assumptions previously approved in the AST amendment to calculate the FHA and CRDA EPU control room χ/Q values for the extended accident duration. The NRC staff qualitatively reviewed the data, inputs, and assumptions used for the assessment and found them generally consistent with site configuration drawings and staff practice. The staff also reviewed the licensee's assessments of control room post-accident dispersion conditions generated from the licensee's meteorological data and atmospheric dispersion modeling for the extended accident duration. On the basis of this review and the staff's confirmatory calculations using ARCON96, the NRC staff concluded that the licensee's estimated control room χ/Q values, listed in Table 2.9.2-2 below, are acceptable for use in the proposed EPU DBA control room radiological consequence assessments. The control room data and assumptions used in the licensee's evaluations, for each of the accidents at EPU conditions, is summarized in Table 2.9.2-5 below.

Offsite Atmospheric Dispersion Factors

In support of the PBAPS AST amendment, the licensee derived both the EAB and LPZ χ/Q values for the MSLB event using the χ/Q algorithm presented in RG 1.5, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Steam Line Break Accident for Boiling Water Reactors" (Reference 82). The licensee calculated EAB and LPZ χ/Q values for the LOCA, CRDA, and FHA events using 1984 through 1988 onsite meteorological data, the PAVAN atmospheric dispersion computer code, and guidance provided in RG 1.145, "Atmospheric Dispersion Models for Potential Accident Consequence Assessments at Nuclear

Power Plants" (Reference 83). The NRC staff qualitatively reviewed the inputs to the PAVAN computer runs and found them generally consistent with site configuration drawings and staff practice. In addition, the staff reviewed the licensee's assessments of EAB and LPZ post-accident dispersion conditions generated from the licensee's meteorological data and atmospheric dispersion modeling. The NRC staff's assessment of the AST EAB and LPZ χ/Q values is discussed in the staff's SE for the PBAPS AST amendment. On the basis of the review, the staff concluded that these χ/Q values were acceptable for use in the AST DBA EAB and LPZ dose assessments. These values became the current licensing basis EAB and LPZ χ/Q values.

In the May 24, 2013, RAI response for the proposed EPU LAR, the licensee noted that while the analysis for the EAB and LPZ χ/Q values for the LOCA remained unchanged from the current licensing basis, the FHA and CRDA was being extended from a 24-hour accident duration to a 720-hour accident duration. The licensee also stated that the EPU MSLB EAB and LPZ χ/Q values were updated using the site-specific calculation used for the LOCA. This differs from the current licensing basis MSLB evaluation which used χ/Q values calculated using guidance from RG 1.5. In response to an NRC staff RAI regarding the MSLB calculation, in Attachment 3 to Supplement 9 to the EPU LAR dated August 22, 2013 (Reference 10), the licensee stated that for the EPU MSLB dose calculation, additional conservatism was added to the dose results by applying the higher PAVAN calculated EAB and LPZ AST LOCA, 0-2 hr ground release χ/Q values rather than the RG 1.5 AST MSLB χ/Q values. The licensee justified this application by stating that since the χ/Q value is a multiplier within the dose calculation, it is acceptable to use the larger current licensing basis LOCA χ/Q values for the EPU MSLB accident because it will generate more conservative dose values. The NRC staff concluded that this was acceptable since the PAVAN computer code is an NRC-accepted method for calculating EAB and LPZ χ/Q values, and the PAVAN EAB and LPZ χ/Q values for the LOCA are more conservative than the current licensing basis MSLB EAB and LPZ χ/Q values calculated using the guidance from RG 1.5.

The licensee used the same meteorological data, inputs, and assumptions previously approved in the AST amendment to calculate the FHA and CRDA EPU EAB and LPZ χ/Q values for the extended accident duration. The NRC staff qualitatively reviewed the inputs and assumptions and found them generally consistent with site configuration drawings and staff practice. In addition, the staff reviewed the licensee's assessments of EAB and LPZ post-accident dispersion conditions generated from the licensee's meteorological data and atmospheric dispersion modeling. On the basis of this review, the staff's confirmatory calculations using PAVAN, and the licensee's use of more conservative χ/Q values for the EPU MSLB, the NRC staff concluded that the EAB and LPZ χ/Q values, listed in Tables 2.9.2-3 and 2.9.2-4 shown below, are acceptable for use in the proposed EPU DBA EAB and LPZ radiological consequence assessments.

EPU LOCA Radiological Consequences

In order to accommodate the increased power level and the associated increase in the LOCA source term, the licensee decreased the allowable leakage in the assumed failed MSIV line from 205 to 150 standard cubic feet per hour (scfh), and decreased the total allowable main steam isolation valve (MSIV) leakage from 360 to 300 scfh. As a result of decreasing the assumed MSIV leakage rate, there will be a corresponding increase in the residence time for activity in the main steam lines (MSLs). The increase in residence time will necessarily result in an increase in the aerosol deposition within the MSLs.

In addition to reducing the allowable MSIV leakage, the licensee re-evaluated the elemental iodine removal efficiencies using the J.E. Cline methodology, (J.E. Cline, "MSIV Leakage Iodine Transport Analysis," Letter Report dated March 26, 1991, (ADAMS Accession Number ML003683718), using the steam line temperature.) This method is referenced in RG 1.183, Appendix A, Section 6.5 as an acceptable method for the evaluation of the reduction in MSIV releases due to holdup and deposition in MSL piping. The re-established elemental iodine removal efficiencies, using the J.E. Cline methodology, are considerably reduced compared to those used in the previously NRC-approved CLTP LOCA analysis which was based on the methodology outlined in AEB 98-03, "Assessment of Radiological Consequences for the Perry Pilot Plant Application using the Revised (NUREG-1465) Source Term," December 9, 1998, (ADAMS Accession Number ML011230531).

The CLTP LOCA analysis assumes that the containment leakage and the related MSIV leakage are reduced after 38 hours due to a reduction in containment pressure. For the EPU analysis, the licensee conservatively assumed that these leakages will remain constant for the duration of the analysis period (720 hours).

As part of the proposed EPU, the licensee plans to increase the isotopic boron-10 enrichment for the standby liquid control (SLC) system. The SLC system is designed to maintain the suppression pool pH at greater than or equal to 7.0 post-LOCA, thereby limiting the re-suspension of iodine from the pool liquid. The use of the SLC system for pH control was previously evaluated by the NRC staff in Section 3.4.3 of SE for the AST amendment. The changes to the SLC system for the proposed EPU are evaluated in Sections 2.8.4.5 and 3.4 of this SE.

The licensee evaluated the radiological consequences resulting from the postulated LOCA at the EPU power level and concluded that the radiological consequences at the EAB, LPZ, and control room comply with the reference values and the control room dose criterion provided in 10 CFR 50.67, and the accident specific dose guidelines specified in SRP Section 15.0.1 and RG 1.183. The NRC staff's review has found that the licensee used analysis, assumptions, and inputs consistent with applicable regulatory guidance identified above. The assumptions found acceptable to the NRC staff are presented in Table 2.9.2-6 shown below and the licensee's calculated dose results are given in Table 2.9.2-1. The NRC staff finds, with reasonable assurance, that the licensee's estimates of the dose consequences of a design-basis LOCA will comply with the requirements of 10 CFR 50.67, and the guidelines of RG 1.183, and are therefore acceptable.

EPU FHA Radiological Consequences

The licensee maintained the analysis methods used in the AST amendment for the evaluation of the FHA under EPU conditions. The only changes made to the CLTP analysis were based on the increased power level and the assumed number of damaged assemblies. The analysis was performed based on plant operation at 102% of the EPU power level of 3,951 MWt, which equates to 4030 MWt. The number of failed pins remains unchanged from the CLTP at 172. However, since the number of pins per assembly is slightly different for the GNF2 fuel assembly used in the EPU analysis, the number of damaged fuel bundles increases from the CLTP quantity of 1.97 failed fuel bundles to the EPU quantity of 2.009 failed fuel bundles.

The licensee evaluated the radiological consequences resulting from a postulated FHA at the for EPU power level and concluded that the radiological consequences at the EAB, outer boundary of the LPZ, and control room are within the reference values and the control room dose criterion provided in 10 CFR 50.67, as well as the accident specific dose guidelines specified in SRP 15.0.1. The NRC staff's review has found that the licensee used analyses, assumptions, and inputs consistent with applicable regulatory guidance identified above. The assumptions found acceptable to the staff are presented in Table 2.9.2-7 shown below, and the licensee's calculated dose results are given in Table 2.9.2-1. The NRC staff finds that all doses estimated by the licensee for the PBAPS, Units 2 and 3, FHA will comply with the requirements of 10 CFR 50.67, and the guidelines of RG 1.183, and are therefore acceptable.

EPU CRDA Radiological Consequences

The licensee maintained the analysis methods used in the AST amendment for the evaluation of the CRDA under EPU conditions. The analysis was performed based on plant operation at 102% of the EPU power level of 3,951 MWt, which equates to 4030 MWt. For conservatism, the licensee increased the amount of fuel melt associated with the CRDA from the CLTP modeled value of 0.77%, to the EPU modeled value of 5.0%.

The licensee evaluated the radiological consequences resulting from a postulated CRDA at the EPU power level and concluded that the radiological consequences at the EAB, outer boundary of the LPZ, and control room are within the reference values and the control room dose criterion provided in 10 CFR 50.67 and the accident specific dose guidelines specified in SRP 15.0.1. The staff's review has found that the licensee used analysis, assumptions, and inputs consistent with applicable regulatory guidance identified above. The assumptions found acceptable to the staff are presented in Table 2.9.2-8 shown below and the licensee's calculated dose results are given in Table 2.9.2-1. The NRC staff finds that the doses estimated by the licensee for the PBAPS, Units 2 and 3, CRDA will comply with the requirements of 10 CFR 50.67 and the guidelines of RG 1.183, and are therefore acceptable.

EPU MSLBA Radiological Consequences

The licensee maintained the analysis methods used in the AST amendment for the evaluation of the MSLBA. Consistent with the CLTP MSLBA, the licensee has verified that for an MSLBA analyzed under EPU conditions, fuel damage would not occur. Therefore, consistent with CLTP evaluation, the released activity is based on the maximum coolant activity allowed by the TSs. Consistent with the CLTP analysis, the licensee based the coolant and steam mass release on a conservative MSIV closure time of 10.5 seconds. This assumption results in a significant increase in the assumed quantities of mass release relative to the actual closure time of 5.5 seconds. For the EPU evaluation, the CLTP mass release was proportionately increased based on the change in power. The MSLBA conservatively assumes that all of the iodine activity in the released coolant mass is released to the environment in a single puff. The licensee analyzed the control room dose assuming that the control room ventilation remained in the normal mode of operation.

The licensee evaluated the radiological consequences resulting from the postulated MSLBA at the EPU power level and concluded that the radiological consequences at the EAB, LPZ, and control room comply with the reference values and the control room dose criterion provided in 10 CFR 50.67, and the accident- specific dose guidelines specified in SRP Section 15.0.1 and RG 1.183. The NRC staff's review has found that the licensee used analysis, assumptions, and inputs consistent with applicable regulatory guidance identified above. The assumptions found acceptable to the NRC staff are presented in Table 2.9.2-9 shown below and the licensee's calculated dose results are given in Table 2.9.2-1. The NRC staff finds, with reasonable assurance, that the licensee's estimates of the dose consequences of a design-basis MSLBA will comply with the requirements of 10 CFR 50.67 and the guidelines of RG 1.183, and are therefore acceptable.

Conclusion

The NRC staff finds that the licensee used analysis methods and assumptions consistent with the conservative regulatory requirements in 10 CFR 50.67 and final GDC-19 and the guidance in RG 1.183. The NRC staff compared the doses at the EPU power level estimated by the licensee to the applicable dose guidelines. The NRC staff finds that the licensee's estimates of the EAB, LPZ, and control room doses will comply with these guidelines. Therefore, the NRC staff finds with reasonable assurance that PBAPS, Units 2 and 3, as modified by this EPU license amendment, will continue to provide sufficient safety margins with adequate defense-in-depth to address unanticipated events and to compensate for uncertainties in accident progression and analysis assumptions and parameters. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to the radiological consequences of DBAs.

Table 2.9.2-1
PBAPS Radiological Consequences Expressed as TEDE[1]
(Values shown in rem)

Design Basis Accidents	EAB [2]	LPZ [3]	CR
Loss of Coolant Accident	9.0	9.6	4.8
Dose Criteria	25	25	5
Fuel Handling Accident	3.0	0.45	4.3
Dose Criteria	6.3	6.3	5
Control Rod Drop Accident [4]	0.31	0.09	0.42
Dose criteria	6.3	6.3	5
Main Steam Line Break Accident [5]	0.27	0.04	0.11
Dose Criteria	2.5	2.5	5
Main Steam Line Break Accident [6]	5.4	0.82	2.1
Dose Criteria	25	25	5

(1) Total effective dose equivalent
(2) Exclusion area boundary
(3) Low population zone
(4) 1200 breached rods; 5% of breached rods melt
(5) Maximum RCS equilibrium iodine activity
(6) Pre-accident iodine spike

Note: Licensee results are expressed to a limit of two significant figures

Table 2.9.2-2
PBAPS Control Room Atmospheric Dispersion Factors

Release Point: Off-Gas Stack
Accident: LOCA Containment and ESF Leakage

Time Interval (Hrs)	χ/Q Value (sec/m^3)
0-0.05	1.18×10^{-3}*
0.05-2	3.31×10^{-6}
2-8	1.00×10^{-15}
8-24	1.00×10^{-15}
24-96	1.64×10^{-8}
96-720	4.54×10^{-9}

* Conservative ground release used during 3 minute containment drawdown

Release Point: U2 TB/RB Exhaust Vent
Accidents: LOCA MSIV Leakage, CRDA

Time Interval (Hrs)	χ/Q Value (sec/m^3)
0-2	1.18×10^{-3}
2-8	9.08×10^{-4}
8-24	4.14×10^{-4}
24-96	2.90×10^{-4}
96-720	2.26×10^{-4}

Release Point: Unit 2 Roof Scuttles
Accident: FHA

Time Interval (Hrs)	χ/Q Value (sec/m^3)$^{(1)}$
0-2	1.90×10^{-3}
2-8	1.33×10^{-3}
8-24	5.96×10^{-4}
24-96	4.18×10^{-4}
96-720	3.27×10^{-4}

Table 2.9.2-3
PBAPS Exclusion Area Boundary Atmospheric Dispersion Factors

Release Point: Off-Gas Stack
Accident: LOCA Containment and ESF Leakage

Time Interval (Hrs)	χ/Q Value (sec/m^3)
0-0.05	9.11×10^{-4}*
0.05-0.5	5.30×10^{-5}
0.5-720	9.17×10^{-6}

* Conservative ground release used during 3 minute containment drawdown

Release Point: U2 TB/RB Exhaust Vent
Accident: LOCA MSIV Leakage

Time Interval (Hrs)	χ/Q Value (sec/m^3)
0-2	9.11×10^{-4}
2-720	9.11×10^{-4}

Release Point: Unit 2 Roof Scuttles
Accident: FHA

Time Interval (Hrs)	χ/Q Value (sec/m^3)[(1)]
0-720	9.11×10^{-4}

Release Point: U2 TB/RB Exhaust Vent
Accident: CRDA

Time Interval (Hrs)	χ/Q Value (sec/m^3)
0-720	9.11×10^{-4}

Release Point: Main Steam Line
Accident: MSLB

Time Interval (Hrs)	χ/Q Value (sec/m^3)
Puff Release	9.11×10^{-4}

Table 2.9.2-4
PBAPS Low Population Zone Atmospheric Dispersion Factors

Release Point: Off-Gas Stack
Accident: LOCA Containment and ESF Leakage

Time Interval (Hrs)	χ/Q Value (sec/m^3)
0-0.05	1.38 E-4 *
0.05-0.5	1.75 E-5
0.5-2	9.05 E-6
2-8	4.01 E-6
8-24	2.67 E-6
24-96	1.10 E-6
96-720	3.10 E-7

* Conservative ground release used during 3 minute containment drawdown

Release Point: U2 TB/RB Exhaust Vent
Accidents: LOCA MSIV Leakage, CRDA

Time Interval (Hrs)	χ/Q Value (sec/m^3)
0-2	1.38 E-4
2-8	5.81 E-5
8-24	3.77 E-5
24-96	1.48 E-5
96-720	4.15 E-6

Release Point: Unit 2 Roof Scuttles
Accidents: FHA

Time Interval (Hrs)	χ/Q Value (sec/m^3)
0-2	1.38 E-4
2-8	5.81 E-5
8-24	3.77 E-5
24-96	1.48 E-5
96-720	4.15 E-6

Release Point: Main Steam Line
Accident: MSLB

Time Interval (Hrs)	χ/Q Value (sec/m^3)
Puff Release	1.38 E-4

Table 2.9.2-5
PBAPS EPU Control Room (CR) Data and Assumptions

Control structure habitability envelope total volume	176,000 ft^3
Control Room Normal Intake Flow	20,600 scfm
Normal Operation Unfiltered Inleakage	1,600 scfm
CREV pressurization flow rate	3,000 scfm
CREV flow rate used in dose analyses	2,700 scfm
CR unfiltered inleakage	500 scfm
CR isolation and CREV initiation	
LOCA	Automatic
FHA	Not credited
CRDA	Not credited
MSLBA	Not credited
Credited manual actions relative to the CREV	None
CREV HEPA filter efficiency credited in the analysis	98%
CREV Charcoal filter efficiency credited in the analysis	89%
CRHE operator breathing rate	
0 - 720 hours	3.5E−04 m^3/sec
CR occupancy factors	
0 - 24 hours	1
24 - 96 hours	0.6
96 - 720 hours	0.4

Table 2.9.2-6
PBAPS EPU Data and Assumptions for the LOCA

Core thermal power level	4030 MWt
Drywell free volume (ft^3)	159,000
Wetwell free volume (ft^3)	127,700
Total free volume (ft^3)	286,700
Drywell peak post LOCA pressure (psig)	49.1
Drywell peak post LOCA temperature (°F)	305
Primary containment leak rate into	
2 min to 720 hours	0.7%/day
Primary containment aerosol deposition	10th percentile Powers Model
Iodine chemical form in containment atmosphere	
cesium iodide	95%
elemental iodine	4.85%
organic iodine	0.15%
Containment sump pH	≥ 7
MSIV leak rate total (4 lines)	300 scfh for 720 hrs @ 49.1 psig
Broken line leakage	150 scfh for 720 hrs @ 49.1 psig
First intact line	150 scfh for 720 hrs @ 49.1 psig
Second and Third intact line	0 scfh for 720 hrs @ 49.1 psig
RB free air volume used (ft^3)	2,500,000
RB Post-LOCA drawdown time assumed	3 minutes
RB mixing efficiency	Not Credited
SGTS filter efficiency	Not Credited
Minimum post-LOCA suppression pool volume	122,900 ft^3
Maximum post-LOCA suppression pool temperature	< 212°F
Chemical Form of Iodine in ESF Leakage	
Elemental	97%
organic	3%
ESF leakage assumption	10 gpm
ESF flash fraction	10%
CREV Initiation	30 minutes after LOCA
CREV air intake flow	2,700 cfm
CREV unfiltered inleakage	500 cfm

Table 2.9.2-7
PBAPS EPU Data and Assumptions for the FHA

Power level	4030 MWt
Minimum post shutdown fuel handling time (decay time)	24 hours
Number of fuel assemblies in core	764
Number of equivalent fuel rods per assembly – GNF2	85.6
Number of failed pins for fuel handling accident	172
Core radial peaking factor	1.7
Limiting Damaged Core Fraction with Power Factor (PF)	0.00447
Reactor Well minimum water level	> 23 feet
Fuel bundle peak burnup will not exceed 62 GWD/MTU	
Fuel clad damage gap fractions	
I-131	8%
Remainder of halogens	5%
Kr-85	10%
Remainder of noble gases	5%
Alkali metals	12%
Pool Dispersion Factors	
Noble gases	1
Aerosols	Infinite
Iodines - limiting event is over the reactor well	200
Duration of release	2 hours
No credit is taken for filtration by the SGTS or Stack	
CR isolation and CREV initiation	Not Credited
Normal flow intake rates with unfiltered inleakage	

Table 2.9.2-8
PBAPS EPU Data and Assumptions for the CRDA

Core thermal power level	4030 MWt
Radial peaking factor	1.7
Number of fuel assemblies in core	764
Number of equivalent fuel rods per assembly - GNF2	85.6
Number of fuel rods damaged in full power CRDA	1200
Fraction of fission product inventory in gap	
Noble gases	0.1
Iodines	0.1
Alkali metals (Cs and Rb)	0.12
Fraction of damaged rods experiencing fuel melt	5%
Fraction of activity in melted regions released to RCS	
Noble gas	100%
Iodines	50%
Others as specified by	Table 1 of Reg. Guide 1.183
Fraction of activity release in RCS reaching condenser	
Noble gas	100%
Iodines	10%
Others	1%
Fraction of activity from condenser available for release to environment	
Noble gas	100%
Iodines	10%
Others	1%
Release rate from condenser:	
To turbine building	1% per day for 24 hours
CR isolation and CREV initiation	Not Credited
Normal flow intake rates, plus an unfiltered inleakage flow, is used	
Control Room Occupancy Factor for 24hr duration of accident	1

Table 2.9.2-9
PBAPS EPU Data and Assumptions for the MSLBA

Core thermal power level		4030 MWt
Noble gas design source term		100,000 µCi/sec after 30 min
Design offgas release rate		403,000 µCi/sec after 30 min
Maximum equilibrium iodine		0.2 µCi/gm DE I-131(Case 1)
Pre-accident iodine spike		4.0 µCi/gm DE I-131(Case 2)
Iodine Isotope Activity	Ci (Case 1)	Ci (Case 2)
1-131	6.38E+00	1.28E+02
1-132	5.85E+01	1.17E+03
1-133	4.26E+01	8.51E+02
1-134	1.06E+02	2.13E+03
1-135	6.12E+01	1.22E+03
Noble Gas Activity		
Kr-83M	6.45E-03	6.45E-03
Kr-85M	1.23E-02	1.23E-02
Kr-85	5.42E-05	5.42E-05
Kr-87	3.35E-02	3.35E-02
Kr-88	3.93E-02	3.93E-02
Kr-89	3.93E-04	3.93E-04
Xe-1 31M	4.45E-05	4.45E-05
Xe-133M	6.45E-04	6.45E-04
Xe-133	1.87E-02	1.87E-02
Xe-1 35M	1.55E-02	1.55E-02
Xe-135	4.90E-02	4.90E-02
Xe-137	1.55E-03	1.55E-03
Xe-138	4.64E-02	4.64E-02
MSIV isolation time assumed		10.5 seconds
Liquid release		189,888 lbm
Steam release		29,670 lbm
CR isolation and CREV initiation		Not Credited
Control Room Envelope		176,000 ft^3

2.10 Health Physics

2.10.1 Occupational and Public Radiation Doses

Regulatory Evaluation

The NRC staff conducted its review in this area to ascertain what overall effects the proposed EPU will have on both occupational and public radiation doses and to determine that the licensee has taken the necessary steps to ensure that any dose increases will be maintained as low as is reasonably achievable (ALARA). The NRC staff's review included an evaluation of any increases in radiation sources and how this may affect plant area dose rates, plant radiation zones, and plant area accessibility. The NRC staff evaluated how doses to personnel needed to access plant vital areas following an accident are affected. The NRC staff considered the effects of the proposed EPU on nitrogen-16 levels in the plant and any effects this increase may have 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 effect this increase may have on radiation doses at the site boundary. The NRC's acceptance criteria for occupational and public radiation doses are based on 10 CFR Part 20; 10 CFR 50.67; 10 CFR Part 50, Appendix I; and final GDC-19. Specific review criteria are contained in SRP Sections 12.2, 12.3, 12.4, and 12.5, Item II.B.2 of NUREG-0737, and other guidance provided in Matrix 10 of RS-001.

Technical Evaluation

The licensee discussed the impact of the proposed EPU with respect to health physics in Section 2.10 of the PUSAR, with additional information provided in Supplements 3 (Reference 4), 11 (Reference 12), 13 (Reference 14), 16 (Reference 17) and 17 (Reference 18) to the EPU LAR. The NRC staff's review is provided below.

Source Terms

Authorization to operate each PBAPS, Units 2 and 3, at 3,951 MWt is approximately a 20% increase from the originally licensed thermal power (OLTP) level of 3,293 MWt, or a 12.4% increase above the currently licensed thermal power (CLTP) level of 3,514 MWt. In general, the production of radiation and radioactive material (either fission or activation products) in the reactor core are directly dependent on the neutron flux and power level of the reactor. Therefore, as a first order approximation, a 12.4% increase in power level is expected to result in a proportional increase in the radiation source terms, both directly from the reactor fuel and indirectly from the reactor coolant. However, due to the physical and chemical properties of the different radioactive materials that reside in the reactor coolant, and the various processes that transport these materials to locations in the plant outside the reactor, several radiation sources encountered in the balance of plant are not expected to change in direct proportion to the increased reactor power. The most significant of these are:

1. The concentration of noble gas and other volatile fission products in the main steam line will not change. The increased production rate (12.4%) of these materials is offset by the corresponding 12.4% increase in steam flow. Although the concentration of these materials

in the steam line remains constant, the increased steam flow results in a 12.4% increase in the rate these materials are introduced into the Main Condenser and Off Gas systems.

2. For the very short-lived activities, most significantly N-16, the decreased transit (and decay time) in the main steam line, and the increased mass flow of the steam results in a larger increase in these activities in the major turbine building components. In general, the dose changes due to N-16 in the equipment above grade can be the most significant factor in skyshine offsite, although radiation scatter from other sources may also be present. The equipment above grade at PBAPS includes steam piping, turbines, feedwater heaters, the upper portions of moisture separators, and the transition between the turbines and condenser.

3. The concentrations of non-volatile fission products, actinides, and corrosion and wear products in the reactor coolant are expected to increase proportionally with the power increase. However, the increased steam flow can result in an increased moisture carryover in the steam, which would result in an increased transport of these activities to the balance of the plant. As part of the proposed EPU, the licensee is installing new steam dryers in the reactor, designed to accommodate the increased steam flow at the uprated power. The licensee has stated that the redesign of the steam dryers will be effective at maintaining the carryover to the current levels of less than 0.1%. With the same steam moisture content, the rate at which non-volatile fission products are introduced into the secondary would be proportional to the steam flow. The actual rate during EPU operations may be somewhat higher or lower, depending on the performance of the redesigned steam dryers. However, the radiation from these non-volatile radioactive materials provides only a small contribution to the dose rates around balance of plant systems during power operations.

Radiation Protection Design Features

1. Occupational and Onsite Radiation Exposures

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 plant design. Due to the design of the shielding and containment surrounding the reactor vessel, and since the reactor vessel is inaccessible to plant personnel during operation, a 20% increase in the radiation sources in the reactor core over the OLTP, will have no effect on occupational worker personnel doses during power operations. Similarly, the radiation shielding provided in the balance of plant (i.e., around radioactive waste systems, main steam lines, the main turbine, etc.) 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. The licensee has determined that dose rate increases due to EPU will remain within acceptable zone designations with the current shielding designs.

Operating at a power level of 120% of OLTP will result in an increased core inventory of radioactive material that is available for release during postulated accident conditions. The plant shielding design must be sufficient to provide control room habitability, per GDC 19, and operator access to vital areas of the plant, per NUREG 0737, "Clarification of TMI [Three Mile Island] Action Plan Requirements," Item II.B.2, during the accident. By letter dated October 15, 2013 (Reference 14), the licensee provided a revised list of vital areas, as defined in NUREG

0737 Item II.B.2, based on the current station physical layout and emergency procedures. The current vital areas include continuous occupancy of the control room (CR) and the Technical Support Center (TSC). Infrequent missions are also needed to the Reactor Building Refueling Floor/Spent Fuel Pool Makeup (Elevation 234'); the Fan Room (Elevation 195'); the Diesel Generator Building; the Radwaste Control Room; the Cable Spreading Room; the Operations Support Center; the Chemistry Lab/Counting Room; and access to, and from, the CR, TSC, and the Main Access Facility. Based on the EPU power level of 3,951 MWt, and a 30-day post-accident occupancy, the licensee calculated doses of 4.8 and 3.77 rem Total Effective Dose Equivalent (TEDE) to operators in the CR and TSC, respectively. The doses calculated by the licensee for individual missions to the Spent Fuel Pool Makeup and Fan Room are 4.36 and 4.43 rem TEDE, respectively. All other mission doses were calculated to be less than 1.5 rem TEDE. These post-accident doses are well within the 5 rem TEDE criteria in final GDC 19 and are acceptable.

2. Public and Offsite Radiation Exposures

There are two factors, associated with this EPU that may impact public and offsite radiation exposures during plant operations. These are the possible increase in gaseous and liquid effluents released from the site, and the possible increase in offsite radiation exposure from radioactive plant components and solid wastes stored onsite, either directly or from atmospheric scatter (known as skyshine).

A. Gaseous and Liquid Effluents

By letter dated January 17, 2014 (Reference 18), the licensee provided the results of their evaluation of the impact of operating at EPU on public doses from liquid and gaseous effluents. Although, as a first order approximation, the increase in effluents is proportional to the increase in reactor power, the licensee chose to demonstrate compliance with 10 CFR Part 50, Appendix I, design objectives by recalculating the expected public doses using updated NRC guidance. The dose values, listed under EPU in Table 2.10-1 below, are calculated at 4030 MWt (102% of maximum EPU power), using the source term assumptions in ANSI/ANS-18.1-1999, "Radioactive Source Term for Normal Operation of Light Water Reactors," and input assumptions and models in Regulatory Guide 1.109 (Reference 84). Calculations were performed with the revised LADTAP and GASPAR programs contained in the 2010 version of the NRCDose computer code.

All of the public doses calculated for EPU, with the updated NRC guidance, are significantly higher than the design basis calculations for the CLTP. In several cases, the doses listed in Table 2.10-1 column 3 (EPU) are more than twice column 2 (CLTP). However, the EPU doses are still a small fraction of the design criteria in 10 CFR 20 Appendix I, and are therefore acceptable.

Table 2.10-1
Maximum Dose to Member of Public from Liquid and Gaseous Effluents

	CLTP **(mrem, both units)**	**EPU** **(mrem, both units)**	**10 CFR 50, Appendix I Design Objective** **(mrem per unit (both units))**
Liquid Effluents			
Total Body Dose All Pathways	0.24	0.68	3 (6)
Maxim Organ All pathways	2.8	3.8	10 (20)
Gaseous Effluents			
Gamma Air Dose	0.72	2.2	10 (20)
Beta Air Dose	0.92	1.18	20 (40)
Max Total Body Dose	0.48	1.48	10 (20)
Max Skin Dose	1.00	2.5	15 (30)

B. Direct Public Radiation Exposure

The licensee has estimated that operating at EPU maximum power can result in as much as a 30% increase in N-16 in the steam in Turbine Building components compared to operation at OLTP. N-16 emits an energetic gamma (6.1 or 7.1 MeV) and can be a source of radiation exposure offsite at older facilities, with small sites, from skyshine. To determine the potential impact of the increased N-16 production could have on the dose to an offsite member of the public, the licensee compared the environmental monitoring data (2010 and 2011 thermoluminescent dosimeter readings) for the public access point nearest the station with the data for off-site control locations 5 to 20 miles from the plant. The data show that the doses for this boundary location are indistinguishable from background doses. In other words, there is negligible (not measurable) skyshine from the facility. Therefore, a 30% increase in gamma radiation from increased N-16 in the Turbine Building would still result in a negligible public dose.

The direct off-site radiation exposure is dominated by radiation emitted from the Independent Spent Fuel Storage Installation (ISFSI), which is not significantly affected by reactor operations at EPU power levels. Based on environmental monitoring measurements, the licensee estimates a dose of 10.8 mrem per year to a potential member of the public located nearest the ISFSI storage pad.

The summing of the 10.8 mrem direct radiation dose, the 0.68 mrem maximum whole body dose from all liquid effluent pathways, and the 1.48 mrem from gaseous effluents, results in a total dose to a member of the public of 12.96 mrem per year. This annual dose is well within the applicable 10 CFR 20 annual limit of 100 mrem, and the 40 CFR 190 annual limit of 25 mrem to a member of the public from the reactor fuel cycle, as referenced by 10 CFR 20.1301 (e).

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 the low flow areas in, reactor systems. The corresponding increase in dose rates associated with these deposited materials will be an additional source of occupational exposure during the repair and maintenance of these systems. However, the current ALARA program practices at PBAPS (i.e., work planning, source term minimization, etc.), coupled with 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 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 Part 20, Appendix I to 10 CFR Part 50, Item II.B.2 of NUREG 0737, and final 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

The licensee discussed the impact of the proposed EPU with respect to human performance in Section 2.11 of the PUSAR, with additional information provided in Supplements 3 (Reference 4), 5 (Reference 6), 13 (Reference 14), 16 (Reference 17), and 18 (Reference 19) to the EPU LAR. The NRC staff's review is provided below.

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 NRC staff's human factors evaluation was conducted to ensure that operator performance is not adversely affected as a result of system 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 final GDC-19, 10 CFR 50.120, 10 CFR Part 55, and the guidance in GL 82-33. Specific review criteria are contained in SRP Sections 13.2.1, 13.2.2, 13.5.2.1, and 18.0.

Technical Evaluation

The NRC staff has developed a standard set of topics for the review of an EPU LAR with respect to human factors. The following topics are addressed below:

1. Changes in Emergency and Abnormal Operating Procedures
2. Changes to Operator Actions Sensitive to Power Uprate
3. Changes to Control Room Controls, Displays and Alarms
4. Changes to the Safety Parameter Display System
5. Changes to the Operator Training Program and the Control Room Simulator
6. Usage of Operating Experience

Each topic below includes the scope of the review consistent with Review Standard RS-001, the information provided by the licensee to address the topic, and the NRC staff evaluation.

1. Changes in Emergency and Abnormal Operating Procedures

1.a Scope

Describe how the proposed EPU will change the plant emergency and abnormal operating procedures. (Reference SRP Section 13.5.2.1)

1.b Information Provided by Licensee

As discussed in Section 2.11.1.1 of the PUSAR, the changes in Emergency Operating Procedures (EOPs) and the Severe Accident Mitigation Procedures (SAMPs) reflect the change in power level and containment accident pressure (CAP) credit elimination, but will not be changed in a manner that involves a change in accident mitigation philosophy.

As discussed in Section 3.2 of Attachment 1 to the EPU LAR, the PBAPS licensing basis currently relies on the use of CAP credit. CAP credit is relied upon to ensure sufficient net positive suction head (NPSH) for the emergency core cooling system (ECCS) pumps following a loss-of-coolant accident (LOCA). As part of the proposed EPU, the licensee is eliminating CAP credit assumptions in the PBAPS safety analysis. Although the current licensing basis credits the use of CAP to assure ECCS pump NPSH requirement is met in these analyses, the EPU analyses will no longer assume CAP credit in the NPSH analyses. The elimination of CAP credit from the licensing basis is accomplished through system modifications and methodology changes that are factored into the safety analyses.

The following actions are being added or changed to the EOPs and Abnormal Operating Procedures (AOPs), as discussed in Section 2.11 of the PUSAR and in Supplements 3 (Reference 4) and 5 (Reference 6) to the EPU LAR:

- A new operator action will be created to place the residual heat removal (RHR) heat exchanger cross-tie valve in service if required to mitigate a rise in suppression pool temperature during an accident or event.
- A new operator action will be created to start a second high pressure service water (HPSW) pump and establish a flow path through the second RHR heat exchanger when the RHR heat exchanger cross-tie is placed in service. In connection with this, there will be an operator action to place the HPSW cross-tie in service, if required.
- Operators will control the depressurization of the units to minimize the impact of a rise in suppression pool temperature associated with the interruption of containment cooling (suppression pool cooling (SPC) or sprays) that occurs upon receipt of a LOCA signal.
- Operating procedures will require the operators to refill the condensate storage tank (CST) from the refueling water storage tank (RWST) during Method "A", "B" and "D" shutdowns (discussed in greater detail in Section 2.5.1.4 of this SE) to provide inventory for the high-pressure coolant injection (HPCI) or reactor core isolation cooling (RCIC) system and maintain the suction of the HPCI and RCIC pumps on the CST rather than the suppression pool, and ensure NPSH margin without the need for CAP credit.
- Operating procedures will be revised to direct the operators to perform new actions to operate key-lock switches in the control room (CR) to inhibit Unit 2 RCIC, and Unit 3 HPCI and RCIC pump automatic suction swap, as applicable, for a fire in certain fire areas.
- The time is reduced in which an operator is required to secure, from the CR, an HPCI pump that has spuriously started from 10 to 7.5 minutes during a Method "A" shutdown without a stuck open relief valve (SORV).
- The time for an operator to initiate alternate shutdown cooling (ASDC) during Method "C" shutdowns is increased from 30 minutes to 14 hours, while the time for initiation of reactor pressure vessel (RPV) depressurization from the CR is decreased from 27.5 minutes to 26.5 minutes for case C1 and 15 to 14.7 minutes for case C2.
- The time for an operator to initiate ASDC during Method "D" shutdowns, without an SORV, is increased from 300 minutes to 364 minutes, while the time for initiation of RPV depressurization from the alternate shutdown (ASD) panel is decreased from 5 to 3.5 hours.
- The time for an operator to initiate SPC from the ASD panel during Method "D" shutdowns with an SORV is decreased from 4 to 2.5 hours, while without an SORV, the time for initiation of SPC is decreased from 180 minutes to 150 minutes.

- The time for an operator to initiate ASDC during Method "D" shutdowns, with an SORV, is increased from 240 to 270 minutes.

- New operator actions are required for Method "D" to address use of new transfer/isolation switches installed on the ASD panels to isolate the control circuits for the 2B and 3D motor control center (MCC) compartments remote transfer switches and align these MCCs to their normal power supplies for a fire in the CR.

- New operator actions are required for Method "D" to address use of new control switches on the ASD panels for the 'B' Loop RHR heat exchanger cross-tie motor operated valves (MOVs), and their associated transfer/isolation switches in emergency bus room panels, to isolate the ASD panel control circuits from control circuits in the CR for a fire in the CR.

- New operator actions are required for Method "D" to direct the operators to ensure the new RHR flow control valves (MO-2-10-2677B & MO-3-10-3677D) are fully open by manually opening these valves at their respective MCC compartment breaker by manipulating the motor contactor and then opening the breakers to preclude spurious mispositioning for a fire in the CR.

- Balance flow through the RHR heat exchangers when operating with the RHR heat exchanger cross-tie open.

- Manually control the transfer of power for the HPSW cross-tie MOV from the Normal to Alternate source or vice versa.

- Manually control the transfer of power from the Normal to Alternate source or vice versa for each of the four new MCC compartments per unit associated with powering the motor-operated RHR flow control valves, RHR heat exchanger cross-tie valves, and the RHR heat exchanger HPSW outlet valves.

1.c NRC Staff Evaluation

The NRC staff has reviewed the list of EOPs and AOPs and the method used by the licensee to identify affected procedures. The licensee stated that the proposed changes do not reflect a change in accident mitigation philosophy. Additionally, the licensee stated that affected procedures, including operating, abnormal, and emergency operating procedures, will be revised and approved prior to implementing EPU. Based on the licensee's statements, the staff has determined that the proposed changes to the EOPs and AOPs and the proposed schedule for revision of the procedures described in the licensee's submittals are acceptable.

2. Changes to Operator Actions Sensitive to Power Uprate

2.a Scope

Describe any new operator actions needed as a result of the proposed EPU. Describe changes to any current operator actions related to emergency or abnormal operating procedures that will occur as a result of the proposed EPU. (Reference SRP Section 18.0)

2.b Information Provided by Licensee

As discussed in Section 2.11.1.2 of the PUSAR, most abnormal events result in automatic plant shutdown (scram). Some abnormal events result in SRV actuation, automatic depressurization system (ADS) actuation and/or automatic ECCS actuation. The licensee further stated that all analyzed events result in safety-related SSCs remaining within their design limits and that EPU does not change any automatic safety function. Changes to subsequent operator action for maintaining core cooling, containment cooling and safe shutdown are described below.

Section 2.11.1.2.1 of the PUSAR discusses changes with respect to operator actions for DBAs and events. These changes are the result of EPU and CAP credit elimination during these events.

- A new operator action will be created to place the RHR heat exchanger cross-tie valve in service, if required, to mitigate a rise in suppression pool temperature during an accident or event.

- A new operator action will be created to start a second HPSW pump and establish a flow path through the second RHR heat exchanger when the RHR heat exchanger cross-tie is placed in service. In connection with this, there will be an operator action to place the HPSW cross-tie in service, if required.

- As part of the CAP credit elimination strategy and managing the interaction between units, operators will control the depressurization of the units to minimize the effect of a rise in suppression pool temperature associated with the interruption of containment cooling (SPC or sprays) that occurs upon receipt of a LOCA signal. Guidance will be provided for the operators to anticipate the rise in suppression pool temperature resulting from an interruption in SPC caused by receiving a LOCA signal when a unit is depressurized to less than 450 psig. The operators will then use the higher suppression pool temperature to verify that the ECCS pump operation will remain within the limits of the NPSH curves during the interruption in containment cooling.

- As part of the CAP credit elimination strategy, operators will manage entry into ASDC, when required, to ensure that suppression pool temperature remains below the limit needed to maintain adequate NPSH for operating ECCS pumps. This will be accomplished by providing guidance in the ASDC procedure for the operator to anticipate a 10 °F rise in suppression pool temperature upon initiation of ASDC, and to verify that ECCS pump operation will remain within the limits of the NPSH curves.

  In an RAI response dated December 20, 2013 (Reference 17), the licensee stated that procedures will prepare the operator to expect a conservative suppression pool temperature rise when ASDC is initiated. The current procedures will be enhanced to use parameters in conjunction with a new curve for determining the expected temperature rise based on the reactor pressure and the suppression pool water level. The procedures will include the following enhancements:

  1. Determine suppression pool temperature prior to initiation of ASDC.

2. Determine the anticipated rise in suppression pool temperature (based on reactor pressure) using the new curve.

3. Add the anticipated rise in suppression pool temperature to current suppression pool temperature to determine the anticipated maximum suppression pool temperature.

4. Plot the maximum anticipated suppression pool temperature on ECCS pump NPSH curve in the EOP.

5. If adequate ECCS pump NPSH is available, initiate ASDC; if not, delay ASDC initiation and re-perform the previous steps after suppression pool temperature has been lowered.

Section 2.11.1.2.2 of the PUSAR, as supplemented by the PUSAR revisions shown in Attachment 4 to Supplement 5 to the EPU LAR (Reference 6), discuss changes with respect to operator actions associated with Appendix R Fire Safe Shutdown Events. As discussed in PUSAR Sections 2.6.5.2 and 2.11.1.2.2, there are four methods designed to bring the plant to a cold shutdown condition for a postulated fire event as follows:

1. Method A utilizes the RCIC system, two SRVs, and one RHR pump to achieve the plant shutdown. CS and HPCI are unavailable. Method A has two case scenarios. Case A1 is Method A without an SORV during the event. Case A2 is Method A with one SORV during the event.

2. Method B utilizes HPCI, two SRVs and one RHR pump to achieve the plant shutdown with CS and RCIC unavailable. Method B also contains two case scenarios. Case B1 is Method B without an SORV during the event. Case B2 is Method B with one SORV during the event.

3. Method C utilizes manual control of three SRVs of the ADS for depressurization of the reactor, and either: (1) one CS pump and one RHR pump in SPC mode, or (2) one RHR pump in both low pressure coolant injection (LPCI) mode and the SPC mode. Method C has 4 case scenarios. Case C1A is Method C without SORV, and core cooling provided by one CS pump. Case C2A is Method C with an SORV, and core cooling provided by one CS pump. Case C1B is Method C without an SORV and core cooling provided by one RHR pump in LPCI mode. Case C2B is Method C with an SORV and core cooling provided by one RHR pump in LPCI mode.

4. Method D utilizes HPCI, two SRVs, and one RHR pump to achieve the plant shutdown. CS and RCIC are unavailable, however, the main control room is evacuated and initiation of safety systems is performed outside of the main control room. Method D also has two case scenarios. Case D1 is Method D without an SORV during the event, and Case D2 is Method D with an SORV during the event.

As discussed in Attachment 4 to Supplement 5 to the EPU LAR (Reference 6), the following changes in operator action and/or response times are required for Fire Safe Shutdown Directive (FSSD) events due to the CAP credit elimination. All of the operator actions below went through a qualitative review with the Operations and Training Departments. Method D was reviewed utilizing the PBAPS CR simulator.

- Operating procedures will require the operators to refill the CST from the RWST during Method A, B and D shutdowns to provide inventory for the HPCI or RCIC system. The HPCI and RCIC pumps maintain suction on the CST, rather than the suppression pool and ensure NPSH margin without the need for CAP credit. Because this will occur about 3 hours after the event and the fire is assumed to be extinguished at 1 hour, operators would not be hampered from reaching the necessary manual valves to perform the action.

- Operating procedures will be revised to provide guidance to manage entry into ASDC in a manner that will mitigate the effect of the rise in suppression pool temperature associated with ASDC initiation in order to maintain NPSH margin for the operating ECCS pumps.

- Operating procedures will be revised to direct the operators to perform new actions to operate key-lock switches in the CR to inhibit Unit 2 RCIC, and Unit 3 HPCI and RCIC pump automatic suction swap, as applicable, for a fire in certain fire areas.

- Operating procedures will be revised to reduce the time in which an operator is required to secure from the CR an HPCI pump that has spuriously started from 10 to 7.5 minutes during a Method "A" shutdown without an SORV.

- During a Method "A" shutdown with an SORV, the time by which an operator must initiate ASDC is unchanged from the current Method "A" requirement of 180 minutes.

- During Method "C" shutdowns, the EPU analysis has determined that the times for initiation of ASDC has increased from 30 minutes to 14 hours, while the time after the event in which the operator must initiate RPV depressurization from the CR has decreased from 27.5 minutes to 26.5 minutes for case C1, and 15 minutes to 14.7 minutes for case C2. These slight decreases in the time of RPV depressurization result in slightly earlier times for low pressure makeup (CS and RHR LPCI mode). However, the actions required for RPV depressurization can all be completed within the new timeframe from the CR.

- During Method "D" shutdowns, without an SORV, the EPU analysis has determined that the times for initiation of ASDC has increased from 300 to 364 minutes, while the time after the start of the event in which the operator must initiate RPV depressurization from the ASD panel has decreased from 5 to 3.5 hours. This is acceptable because, per procedures, operators will depressurize maintaining acceptable vessel temperature.

- During Method "D" shutdowns, with an SORV, the EPU analysis has determined that the time after the event for initiation of SPC from the ASD panel has decreased from 4 to 2.5 hours, while without an SORV, the time for initiation of SPC has decreased from 180 to 150 minutes. However, a single operator is able to complete required actions in 2 hours or less.

- During Method "D" shutdowns, with an SORV, ASDC initiation time is increased from 240 to 270 minutes.

- New operator actions are required for Method "D" to address use of new transfer/isolation switches installed on the ASD panels to isolate the control circuits for the 2B and 3D MCC compartments remote (i.e., CR) transfer switches and align these MCCs to their normal power supplies. In each of these cases, no time challenges were identified that would prevent completion of these actions in accordance with the revised response time.

- New operator actions are required for Method "D" to address use of new control switches on the ASD Panels for the B Loop RHR heat exchanger cross-tie MOVs, and their associated transfer/isolation switches in emergency bus room panels, to isolate the ASD panel control circuits from control circuits in the CR. In this case, no time challenges were identified that would prevent completion of these actions in accordance with the revised response time.

- New operator actions are required for Method "D" to direct the operators to ensure the new RHR flow control valves (MO-2-10-2677B and MO-3-10-3677D) are fully open by manually opening these valves at their respective MCC compartment breaker by manipulating the motor contactor and then opening the breakers to preclude spurious mispositioning. In this case, no time challenges were identified that would prevent completion of these actions in accordance with the revised response time.

The licensee further stated in Attachment 4 to Supplement 5 to the EPU LAR that, in recognition that multiple manual actions in support of FSSD functions may be required of operators during response to fire events, a review of the operator timeline analyses included in the FSSD calculations was performed. This review assessed the actions required to initiate ASDC, initiate SPC, depressurize the RPV, and provide makeup inventory to the CST, including the new and revised operator actions discussed above. No fire areas were identified where operator availability or time constraints would prevent completion of the required actions in accordance with the revised response times.

With respect to operator actions associated with an Anticipated Transient Without Scram (ATWS) event, the licensee stated in Section 2.11.1.2.3 of the PUSAR that a new operator action will be created to refill the CST from the RWST about 90 minutes after the start of the event. This is a reasonable action because the reactor is shut down in approximately 30 minutes and the CST inventory would last for an additional hour at the estimated injection rate.

The licensee concluded in Section 2.11.1.2.4 of the PUSAR that the changes to the PBAPS, Units 2 and 3, operator actions, as a result of the EPU, do not significantly affect operator actions. The changes will be appropriately revised in the procedures and the operators will receive appropriate classroom and/or simulator training for implementation. There are no new or revised operator workarounds as a result of EPU.

2.c NRC Staff Evaluation

In RAI response letters, dated October 15, 2013 (Reference 14), and December 20, 2013 (Reference 17), the licensee stated that a human factors evaluation was performed for the new EOP and AOP tasks, and it was determined through this evaluation that all new tasks use skills and abilities similar to those required for existing tasks. In addition, the Exelon Configuration Change Process requires an Operations review of the modifications to assess the operations impact of the changes. This review also includes assessment of the integration of these actions into plant procedures. This includes consideration of the expected plant response during these actions, and the availability of instrumentation to monitor the plant and equipment considerations and determine the effectiveness of their actions. Additionally, any new or changed operator actions for DBAs and special events were evaluated using the requirements in the Peach Bottom Operator Response Time Program. This process compared the time when the action was required to the expected performance times. Validation for expected performance times were devised from simulator runs, plant walkthroughs, or benchmarking against other existing operator actions that were previously validated by simulator runs and walkthroughs. Because these evaluations were completed using an already existing validation process and the impacts of the changes were evaluated and actions were incorporated into plant procedures, the NRC has determined that these changes are acceptable.

3. Changes to Control Room Controls, Displays and Alarms

3.a Scope

Describe any changes the proposed EPU will have on the operator interfaces for control room controls, displays, and alarms. For example, what zone markings (e.g. normal, marginal and out-of-tolerance ranges) on meters will change? What setpoints will change? How will the operators know of the change? Describe any controls, displays, alarms that will be upgraded from analog to digital instruments as a result of the proposed EPU and how operators will be tested to determine they could use the instruments reliably. (Reference SRP Section 18.0)

3.b Information Provided by Licensee

As discussed in Section 2.11.1.3 of the PUSAR, changes to the CR are prepared in accordance with the plant design change process. Under this process, a human factors engineering review is performed. The change process also requires an effects review by operations and training personnel. Results of these reviews, including simulator effects and training requirements, are incorporated into the engineering change package and tracked to completion by the design change process.

Section 2.11.1.3 of the PUSAR, as supplemented by the PUSAR revisions shown in Attachment 4 to Supplement 5 to the EPU LAR (Reference 6), stated that the following changes will be made to the CR controls, displays and/or alarms resulting from EPU:

- A switch and position indicating lights will be provided for the new RHR heat exchanger cross-tie MOV controls in each division of RHR and for each of the new flow control valves at the inlets to the RHR heat exchangers. New cross-tie flow indicators allow operators to balance flow through the heat exchangers when operating with the RHR heat exchanger cross-tie open.

- Position indicating lights will be provided to indicate LPCI flow control valve position corresponding to minimum and maximum allowable flow. An alarm will also be provided to indicate when the valve is outside of the allowable flow range.

- A new selector switch is provided for manually controlling the transfer of power for the high pressure service water cross-tie MOV from the normal to alternate source or vice versa.

The indicating lights will show if power is available on the normal and alternate sources. Annunciator windows will be provided in the CR to alert the operators when any of the transfer switches has an off-normal condition.

- The turbine-generator and auxiliaries modifications will require changes to CR controls and alarms due to the upgrades to the Alterrex rectifier and voltage regulator.

- The addition of the third main steam spring safety valve (SSV) will include valve instrumentation (acoustic monitor and temperature element). The instrumentation indication will be available in the CR. Instrumentation and alarms for the new SSV will be consistent with that of the existing SSVs.

- Key-lock control switches will be provided to give the operators the capability of manually inhibiting Unit 2 RCIC, and Unit 3 HPCI and RCIC pump automatic suction swap, as applicable, for a fire in certain fire areas. Annunciator windows will be provided in the CR to alert the operators when any of the key-lock switches has an off-normal condition.

- A transfer switch control switch is provided for manually controlling the transfer of power from the normal to alternate source or vice versa for each of the four new MCC compartments per unit associated with powering the motor-operated RHR flow control valves, RHR heat exchanger cross-tie valves, and the RHR heat exchanger high pressure service water outlet valves. The indicating lights will show if power is available on the normal and alternate sources. Annunciator windows will be provided in the control room to alert the operators when any of the new MCC compartments with transfer switches has an off-normal condition.

3.c NRC Staff Evaluation

The licensee has indicated that changes to the CR are prepared in accordance with the plant design change process. Under this process, a human factors engineering review is performed for changes associated with the PBAPS CR. The licensee has also indicated that the change process also requires an effectiveness review by operations and training personnel. Furthermore, the licensee has indicated that results of these reviews, including simulator effects and training requirements, are incorporated into the engineering change package and tracked to completion via the design change process.

Any new or changed operator actions for design basis accidents and special events were evaluated using the requirements in the Peach Bottom Operator Response Time Program. This process compared the time when the action was required to the expected performance times. Validation for expected performance times were devised from simulator runs, plant walkthroughs, or benchmarking against other existing operator actions that were previously validated by simulator runs and walkthroughs. In addition, operator training for changes to CR interfaces, alarms, and indications will be accomplished in accordance with the plant training and simulator program. Operator training will be presented in the classroom and on the simulator for the RHR and high pressure service water cross-tie modifications. Licensed and non-licensed operator training will be provided prior to the cycle implementing the changes and will focus on plant modifications, procedure changes, startup test procedures, and other aspect of the EPU including changes to parameters, set points, scales and systems. The NRC staff finds this approach acceptable. In addition, because the licensee used already approved change processes and personnel to perform changes to the CR displays and alarms, and because the proposed CR changes seem reasonable given the modifications associated with the proposed EPU, the NRC staff finds the CR changes acceptable.

4. Changes to the Safety Parameter Display System

4.a Scope

Describe any changes to the safety parameter display system (SPDS) resulting from the proposed EPU. How will the operators know of the changes? (Reference SRP Section 18.0)

4.b Information Provided by Licensee

As discussed in Section 2.11.1.4 of the PUSAR, the purpose of the PBAPS SPDS is to continuously display information from which plant safety status can be readily and reliably assessed. The principal function of the SPDS is to aid CR personnel during abnormal and emergency conditions in determining the safety status of the plant and in assessing whether abnormal conditions warrant corrective action by operators to avoid a degraded core.

Section 2.11.1.4 of the PUSAR, as supplemented by the PUSAR revisions shown in Attachment 4 to Supplement 5 to the EPU LAR (Reference 6), stated that the following changes will be made to the SPDS as a result of PBAPS EPU:

- The heat capacity temperature limit curve will be revised as a result of the decay heat rejected to the suppression pool.
- The pressure suppression pressure PSP curve will be revised as a result of the increase in reactor power and in decay heat loading.
- The net positive suction head (NPSH) curves for RHR and core spray pumps will be revised due to utilization of the 3% NPSH curves.
- Position indication will be provided for the additional third SSV in each unit.
- RHR flow indication for each of the RHR subsystems will show RHR flow rate through each subsystem effectively showing flow through the RHR cross-tie piping.
- The percentage of the standby liquid control tank volume required to achieve hot shutdown boron weight will change due to the increase in Boron-10 enrichment.

The operators will receive appropriate classroom and/or simulator training for implementation of the above changes.

4.c NRC Staff Evaluation

The SPDS changes will be made in accordance with the configuration change process and the operators will receive appropriate classroom and/or simulator training for implementation. Therefore, the NRC staff finds these changes to be acceptable.

5. Changes to the Operator Training Program and the Control Room Simulator

5.a Scope

Describe any changes to the operator training program and the plant referenced control room simulator resulting from the proposed EPU, and provide the implementation schedule for making the changes. (Reference SRP Sections 13.2.1 and 13.2.2)

5.b Information Provided by Licensee

As discussed in Section 2.11.1 of the PUSAR, and UFSAR Section 13.3, the PBAPS training program incorporates the requirements specified in ANSI N18.1-1971, "Selection and Training of Nuclear Power Plant Personnel;" 10 CFR Part 55, "Operators' licenses," and 10 CFR 50.120 "Training and qualification of nuclear power plant personnel." The PBAPS training program is based on a systematic approach to training. The qualifications for licensed operators, including compliance with 10 CFR Part 55, are described in UFSAR Section 13.2. The operator training program is accredited by the Institute of Nuclear Power Operations (INPO).

Section 2.11.1.5 of the PUSAR states that training of operations personnel will occur on all EPU modifications necessary to support operation at EPU conditions. The operator training is presented in the classroom and on the simulator. The major EPU change for the CR operators involves the installation of the RHR and high pressure service water cross-tie modifications.

Section 2.11.1.5 of the PUSAR states that licensed and non-licensed operator training will be provided, prior to the cycle implementing the changes, and will focus on plant modifications, procedure changes, startup test procedures, and other aspects of EPU including changes to parameters, set points, scales, and systems. The applicable lesson plans will be revised to reflect changes as a result of the EPU. Simulator training during this phase will also include training on performance effects of new modifications; this will support the power ascension plan. Prior to startup following the refueling outage for EPU, the operators will be given classroom and simulator Just-In-Time training to cover last minute training items and perform startup training and startup testing evolutions on the simulator. Successful completion of training is verified, as required by plant procedures, as part of the turnover of the modification to operations.

Section 2.11.1.5 of the PUSAR states that the simulator is a duplicate of the PBAPS, Unit 2, main control room and, as such, is modified when modifications affecting simulator fidelity are installed in the plant. Use of the simulator to support PBAPS, Unit 3, related training is performed when there are unit differences between the simulator and Unit 3. Classroom training is provided relative to the implementation of modifications to both PBAPS units. Human errors are prevented through rigorous training in the classroom and plant settings prior to completion of modifications at each unit. The training includes evaluation tools such as written exams, simulator evaluations, and task performance tools as deemed appropriate.

Section 2.11.1.5 of the PUSAR further states that installation of the EPU changes to the simulator are performed in accordance with ANSI/ANS-3.5 1998, "Nuclear Power Plant Simulators for Use in Operator Training and Evaluation." The simulator changes will include hardware changes for new and modified control room instrumentation and controls, software updates for modeling changes due to EPU (i.e., reactor feed pump, condensate pump modifications), set point changes, and re-tuning of the core physics model for cycle-specific data. The simulator process computer will be updated for EPU modifications. Operating data will be collected during EPU implementation and start-up testing. This data will be compared to simulator data as required by ANSI/ANS-3.5 1998. Additionally, simulator acceptance testing will also be conducted to benchmark the simulator performance based on design and engineering analysis data. Lessons learned from power ascension testing and operation at EPU conditions will be fed back into the training process to update the training material and processes as required.

5.c NRC Staff Evaluation

The NRC staff finds the licensee's changes to the operator training program and control room simulator acceptable because: (1) the training program, described in UFSAR Section 13.3, incorporates the requirements specified in ANSI 18.1-1971; (2) the training program is based on a systematic approach to training; (3) the qualifications for licensed operators, including compliance with 10 CFR Part 55, are described in the UFSAR; (4) the operator training program is accredited by INPO; (5) the licensee's uses controlled processes to identify training needs and simulator updates; and (6) the proposed training will be developed and completed prior to operation under EPU conditions.

6. Usage of Operating Experience

6.a Scope

Describe any information pertaining to the human factors issues related to predecessor plants, unresolved safety issues/generic safety issues, Three Mile Island issues, Generic Letters and Information Notices, NRC Office for the Analysis and Evaluation of Operational Data (AEOD) reports, and any other operating plant event reports. (Reference SRP Section 18)

6.b Information Provided by Licensee

As discussed in Attachment 3 to Supplement 3 to the EPU LAR (Reference 4), the following activities were performed by the licensee to identify human factors lessons-learned:

- Reviewed industry lessons-learned via INPO 09-005, March 2009, "Power Uprate Implementation Strategies - A Leadership Perspective."

- Reviewed industry lessons-learned via INPO Significant Event Report 05-2, "Lessons Learned from Power Uprates."

- Reviewed power ascension plans from Nine Mile Plant, Unit 2, and Grand Gulf Nuclear Station, Unit 1 (GGNS).

- Participated in industry licensing manager's peer group for power uprates.

- Performed benchmarking with GGNS, Turkey Point Nuclear Generating Station, and Susquehanna Steam Electric Station.

The licensee further stated that the following initiatives were applied from the lessons learned:

- Assignment full-time of two currently licensed operators to the EPU project.

- Assessment of changes to operating margins of equipment and systems to identify, evaluate and address potential operator challenges.

- Involvement of station organizations in the development and review of changes related to the EPU project.

6.c NRC Staff Evaluation

Consistent with the guidance in SRP Section 18.0, the NRC staff reviewed the above activities against the general intent of the usage of operating experience as described in staff guidance in Section 3.4.1 of NUREG-0711, "Human Factors Engineering Program Review Model." The NRC staff has determined that the activities stated above are satisfactory for meeting usage of operating experience, and therefore, has determined that these activities are acceptable.

Conclusion

The NRC staff has reviewed the changes to operator actions, human-system interfaces, procedures, and training required for the proposed EPU and concludes that the licensee has: (1) appropriately accounted for the effects of the proposed EPU on the available time for operator actions; and (2) taken appropriate actions to ensure that operator performance is not adversely affected by the proposed EPU. The NRC staff further concludes that the licensee will continue to meet the requirements of final 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

2.12.1 Approach to EPU Power Level and Test Plan

Background

As discussed in SE Sections 1.2 and 1.3, the license proposes to use a Constant Pressure Power Uprate (CPPU) approach to increase the maximum power level from 3514 MWt to 3951 MWt. The EPU LAR represents an increase of approximately 20 percent above the original licensed thermal power (OLTP) level of 3293 MWt and an increase of approximately

12.4 percent above the current licensed thermal power (CLTP) level of 3514 MWt. The planned implementation outages to accomplish the EPU are in 2014 and 2015 for PBAPS, Units 2 and 3, respectively. On October 18, 1994 (Unit 2), and July 18, 1995 (Unit 3), the NRC approved a 5 percent stretch power uprate (SPU) that authorized an increase in the maximum thermal power level from 3293 MWt (OLTP) to 3458 MWt. On November 22, 2002, the NRC approved a 1.62 percent measurement uncertainty recapture (MUR) uprate that authorized an increase in the maximum thermal power level from 3458 MWt to 3514 MWt (CLTP).

As discussed in SE Section 1.3, the technical bases for the EPU LAR follow the guidelines contained in the following NRC-approved GE LTRs for EPU safety analysis: (1) NEDC-33004P-A, "Constant Pressure Power Uprate," commonly referred to as CLTR (Reference 20); (2) NEDC-32424P-A, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," commonly referred to as ELTR1 (Reference 21); and (3) NEDC-32523P-A, "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate," commonly referred to as ELTR2 (Reference 22). The NRC staff guidance for reviewing EPU test programs is described in SRP Section 14.2.1, "Generic Guidelines for Extended Power Uprate Testing Programs," dated August 2006. The staff review focused on whether the licensee adequately addressed the guidance described in the SRP.

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 conformance of the test program with applicable NRC regulations. The acceptance criteria defined by the NRC for the proposed EPU test program are based on 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," which requires establishment of a test program to demonstrate that SSCs will perform satisfactorily in service. Specific review criteria are contained in SRP Section 14.2.1. Guidance is also provided in Section 2 and Insert 12 of RS-001.

The licensee's proposed power ascension and test plan (PATP) follows the guidelines contained in NRC-approved GE LTRs, which the NRC staff determined to be an acceptable methodology for licensees requesting EPUs.

Technical Evaluation

2.12.1.1 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 OLTP level; and (2) initial power ascension tests that were performed at lower power levels if the EPU would invalidate the test results. The licensee should either repeat initial power ascension tests within the scope of this comparison or provide justification for deviations that are proposed. The following specific criteria should be identified in the EPU test program:

- all initial power ascension tests 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 NRC staff reviewed applicable sections of the PBAPS UFSAR, Section 13.5, "Startup and Power Test Program," which provided general requirements and an overview of initial startup tests performed. The staff also reviewed information which described the general requirements and startup and power ascension testing performed from initial plant startup to full-rated power of 3293 MWt, to demonstrate that the plant was capable of operating safely and satisfactorily. The staff also reviewed the following information provided in the PBAPS EPU LAR:

- Section 2.12, "Power Ascension and Testing Plan," of the PUSAR. The PUSAR (Attachment 6 to the EPU LAR) is an integrated summary of the results of the safety analysis and evaluations performed specifically for the PBAPS EPU and follows the guidelines contained in the CLTR. As discussed in Section 10.5.8 of the NRC staff's SE for the CLTR, the staff did not accept the proposed generic elimination of large transient testing (LTT) for CPPU. The SE indicated that this issue needs to be addressed on a plant-specific basis in the PUSAR.
- Attachment 9 to the EPU LAR, "Planned Modifications to Support Extended Power Uprate," provides a list of modifications planned for EPU implementation. The planned modifications will be implemented in accordance with the requirements of 10 CFR 50.59.
- Attachment 10 to the EPU LAR, "Startup Test Plan," describes the startup testing that Exelon will conduct associated with implementation of EPU at PBAPS. The presentation of information is organized based on SRP14.2.1. The attachment also provides a discussion of the EPU testing planned and provided a comparison in Table 10-1 of the initial startup and EPU planned testing. Section 5.0 of Attachment 10 provides a justification for not performing certain LTT. The attachment supplements the information in Section 2.12 of the PUSAR.

The NRC staff notes that all transient tests described in the initial startup test program were listed in Table 10-1 of Attachment 10 to the EPU LAR; and that Section 4.1 of Attachment 10 provided a discussion of power ascension startup tests initially performed greater than 80 percent of OLTP. The staff also noted that two LTTs, SUT 25 and SUT 31, performed at power levels less than 80 percent of OLTP, would not be invalidated by the PBAPS EPU. Transient test SUT 25, "Closure of all main steam isolation valves (MSIVs)," was initially performed at 50 and 75 percent of OLTP; and SUT 31, "Generator Load Rejection Test and

Turbine Trip Test," was performed at 25 percent of OLTP. These tests are similar to the tests described in Table 2 of SRP 14.2.1.

The licensee's PATP does not include performing LTTs at full EPU power. The justification for not performing such tests was presented by the licensee in Section 5.0 of Attachment 10, which provides an overview of the PATP covering power ascension up to the full EPU. The requested full EPU power level is 3951 MWt, an increase of approximately 12.4 percent above the CLTP level of 3514 MWt. Table 10-2 of Attachment 10 of the LAR summarized the planned EPU power ascension testing. The licensee's justification for a test program that does not include all of the power ascension testing that would normally be performed is discussed further in SE Section 2.12.1.3.

The PATP is primarily an initial power ascension test plan designed to assess steam dryer/separator performance and selected piping system performance from CLTP to the uprated power level. The licensee also plans 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 made along an established flow control/rod line in increments of equal to or less than 5 percent power. Steady-state data will be taken at points from 90 up to 100 percent of CLTP so that system performance parameters can be projected for EPU power before the CLTP is exceeded. Power ascension will occur over an extended period of time with gradual increases in power and hold points.

The licensee is also performing post-modification testing, calibration and normal surveillance, as required, to ensure that systems will operate in accordance with their design requirements. The NRC staff compared the documents referenced above, and reviewed the initial startup tests and planned EPU power ascension testing described in Table 10-2 of Attachment 10 to the EPU LAR and applicable sections of the PBAPS UFSAR. The staff concludes that the proposed PATP conforms to the NRC's acceptance criteria in 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," including specific review criteria contained in SRP Section 14.2.1 and other staff guidance provided in RS-001. Therefore, the proposed PATP is acceptable.

2.12.1.2 SRP 14.2.1, Section III.B, Power Ascension Test Considerations for Plant Modifications

Section III.B of SRP 14.2.1 specifies the guidance and acceptance criteria that the licensee should use to assess the aggregate impact of EPU plant modifications, setpoint adjustments, and parameter changes that could adversely impact the dynamic response of the plant to an anticipated operational occurrence (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 a loss of all offsite power, tripping of the main turbine generator set, or the loss of power to all reactor coolant pumps. The EPU test program should adequately demonstrate the performance of SSCs important to safety that meet any of the following criteria: (1) the performance of the SSC is impacted by EPU-related modifications; (2) the SSC is used to mitigate an AOO described in the plant-specific design basis; and, (3) performance of the SSC can be affected by integrated plant operation or transient conditions.

The NRC staff reviewed Attachment 9 to the EPU LAR that describes the planned modifications necessary to support the EPU which will be implemented over several years in refueling outages P2R19 (completed in 2012), P3R19 (completed in 2013), P2R20 (planned for 2014),and P3R20 (planned for 2015). The staff also reviewed Section 4.2 of Attachment 10 to the EPU LAR which describes the licensee's aggregate impact analysis of the modifications necessary to support the proposed EPU. Post-modification testing associated with the proposed modifications include functional performance checks, component performance measurements, equipment calibrations and pressure drop measurements at full flow conditions. The licensee stated that aggregate impact of EPU plant modifications, set-point adjustments and parameter changes will be demonstrated by a test program established for a BWR EPU in accordance with startup test specifications as described in PUSAR Section 2.12.1, "Approach to EPU Power Level and Test Plan." 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 EPU.

The licensee stated that most modifications will have been implemented for one to two full operating cycles in advance of EPU 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 the licensee for EPU include changes to the high pressure main turbine, condensate pump and motor upgrades, modifications to six reactor feed pump turbines, main generator rotor modifications and feedwater heater replacements.

The NRC staff concludes that the plant modifications associated with the proposed EPU were adequately considered in development of the PATP. Specifically, the staff concludes that based on a review of the listing of completed and planned modifications, including post maintenance testing associated with these modifications, the proposed EPU test program will adequately demonstrate the performance of the SSCs. The staff also concludes that the proposed PATP adequately identifies plant modifications necessary to support operation at the uprated power level and complies with the criteria established in Section III.B of SRP 14.2.1.

2.12.1.3 SRP 14.2.1, Section III.C, Justification for Eliminating EPU 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. 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 following factors should be considered, as applicable, when justifying elimination of power ascension tests:

- previous uprate operating experience;

- introduction of new thermal-hydraulic phenomena or identified system interactions;

- facility conformance to limitations associated with computer modeling and analytical methods;
- plant operator familiarization with facility operation and trial use of operating and EOPs;
- minimal reductions in the margin of safety;
- guidance contained in vendor topical reports; and
- risk implications.

The PATP is relied upon as a quality check to: (1) confirm that analyses and any modifications and adjustments that are necessary for the proposed EPU have been properly implemented; and (2) benchmark the analyses against the actual integrated performance of the plant. This is consistent with 10 CFR Part 50, Appendix B, which notes 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. In addition, 10 CFR Part 50, Appendix B, also 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.

As discussed in Section 5.1 and shown in Table 5-2 of Attachment 10 to the EPU LAR, ELTR1 requires an MSIV closure test be performed for EPU if the power uprate is more than 10 percent above any previous recorded MSIV transient data. Similarly, ELTR1 states that a generator load reject test will be performed for EPU if the power uprate is more than 15 percent above any previous recorded generator load rejection transient data. The proposed PBAPs EPU represents an increase over the CLTP of 12.4 percent. The licensee stated that, in 2003, PBAPS, Unit 2, had an MSIV closure event and a generator lockout (both events at 100 percent CLTP). Based on these events, the generator load rejection test would not be required per ELTR1, since the proposed EPU is less than 15 percent. However, the MSIV closure event test would be required since the proposed EPU is greater than 10 percent. However, the licensee took exception to the ELTR1 criteria for MSIV closure testing and provided a justification for the elimination of the MSIV closure test as part of the EPU PATP. The licensee's justification for not performing LTT is discussed further below.

The NRC staff reviewed the licensee's justification for not performing certain original startup tests against the review criteria established in SRP 14.2.1. The licensee presented its justification in Section 5.0 of Attachment 10 to the LAR, including Tables 5-1 thru 5-3. The licensee stated that LTT is not required for EPU because plant transient performance has been baselined by startup testing, actual plant-specific transient events, post modification testing, advances in analytical techniques, extensive BWR post-EPU transient operating experience at power levels greater than OLTP, and performance of an EPU probabilistic risk assessment. The PBAPS PATP does not include all the power ascension LTT that would typically be performed during initial startup. The original startup MSIV closure test was performed at 100 percent of OLTP, the plant response to an MSIV closure event has since been demonstrated at 100 percent of CLTP (89 percent of EPU power level). The licensee concluded that based on these plant-specific historical data and EPU analytical results, the MSIV closure event results in conditions that are within design limits. The licensee also provided a detailed discussion of the basis for elimination of certain LTTs (e.g., MSIV closure and generator load rejection), pursuant to the review criteria established in Section III.C.2 of SRP 14.2.1. The licensee stated in the application that MSIV full closure testing at 100 percent rated power during EPU power ascension is not required because the plant response at EPU conditions is expected to be similar to the documented response during initial startup testing and actual transients that have occurred during plant operation. Additionally, deliberately closing all MSIVs from 120 percent of OLTP will result in an undesirable transient cycle on the primary system that can reduce equipment service life. The following two LTTs were performed during initial startup of both units, as discussed in Attachment 10 to the LAR and Section 13.5 of the PBAPS UFSAR.

- Full Closure of all MSIVs

  This initial startup test (SUT 25) required a simultaneous full closure of all MSIVs initiated from 100 percent of OLTP, with single MSIV closure performed at 50, 75, and 80 percent of OLTP. The test objectives were to functionally check the MSIVs for proper operation at selected power levels, determine isolation valve closure times, and to determine reactor transient behavior during and following simultaneous closure of all MSIVs. The test also determined the maximum power at which a single valve closure can be made without a scram. As reported in Attachment 10 to the EPU LAR, all acceptance criteria for MSIV closure startup testing were satisfied; proper MSIV operation was demonstrated; and closure times verified at various power levels. MSIV closure times and reactor parameters were monitored and found acceptable when compared to predicted results.

- Generator Load Rejection and Turbine Trip

  This initial startup test (SUT 31) was performed to determine reactor response and turbine overspeed following a generator trip; and also to demonstrate the proper response of the reactor and its control systems following trips of the turbine and generator. During the test, the turbine stop valves were tripped at selected reactor power levels and during the simultaneous opening of the main generator output breakers. The test was performed at 25 percent of OLTP and included a loss of all offsite power. The licensee stated that additional startup testing of the turbine stop and control valve closure at power levels up to 100 percent of OLTP verified the reactor transient responses and compliance with all acceptance criteria.

BWR Industry Post-EPU Transient Experience

With respect to the review criteria established in SRP 14.2.1, Section III.C.2, the licensee cited the examples shown below of BWR industry transient events that occurred at plants presently operating at EPU power levels. It should be noted that the NRC staff review of the licensee event reports (LERs) associated with these events indicated power levels at the time of the event greater than OLTP. The following examples of EPU transient experience at uprated BWRs similar to that of PBAPS demonstrates successful response to transient events such as

MSIV closure and generator load rejection at EPU rated power levels of 110-120 percent of OLTP.

Edwin I. Hatch (Hatch) Nuclear Plant - 15% Approved EPU (BWR4 with Mark I containment)

Several events, including a turbine trip and a generator load reject event subsequent to its uprate, occurred at Hatch Nuclear Plant, as reported in LERs 2000-004 and 2001-002. According to the NRC staff's review of the LERs, the behavior of the primary safety systems was as expected. In LER 2000-004 for Unit 2, a turbine trip and reactor scram occurred while operating at 99.7 percent of rated thermal power (2754 MWt) and was caused by the failure of a vibration instrument located on the #10 bearing. The LER reviewed by the NRC staff reported that the event had no adverse impact on nuclear safety. For LER 2001-002, Unit 1 was at 100 percent of rated thermal power of 2763 MWt (full EPU approved power level of 113 percent of OLTP) at the time of the main turbine trip. In May 1999 (LER 1999-005), Hatch Nuclear Plant, Unit 2, experienced an unplanned event that resulted in a generator load reject from 98.3 percent of uprated power (approximately 112.7 percent of OLTP).

The NRC staff review of the LERs identified that all systems functioned as expected and per the design, given the water level and pressure transients caused by the turbine trip and reactor scram. In 1998, the NRC approved an EPU for 113 percent of OLTP (2763 MWt) for both units. Two additional reactor scram events occurred on April 5, 2006 (LER 2006-002), and July 4, 2008 (LER 2008-003), while operating at 115 percent of OLTP. All required safety systems functioned as expected, given the water level and pressure transients caused by the turbine and reactor trips.

Brunswick Steam Electric Plant - 20% Approved EPU (BWR4 with Mark I containment)

Licensed by the NRC to 120 percent of OLTP in May 2002, Brunswick, Unit 2, experienced an unplanned generator and turbine trip on November 4, 2003, which occurred at 115.2 percent of OLTP (96 percent of uprated thermal power), and resulted in a reactor protection system actuation. As noted by 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 Final Safety Analysis Report. On July 13, 2005 (LER 2005-005), Unit 1 scrammed from 120 percent of OLTP due to the failure of the main generator no load disconnect switch, causing a turbine trip and control valve fast closure. Both the plant and operator response to this event was as expected.

Dresden Nuclear Power Station - 17% Approved EPU (BWR3 with Mark I containment)

In December 2001, the NRC approved an EPU for 117 percent of OLTP (2868 MWt) for both units. On January 30, 2004 (LER 2004-002), Dresden, Unit 3, experienced an automatic scram due to a main turbine trip from low lube oil pressure while the plant was operating at 97 percent power (approximately 113 percent of OLTP). On July 4, 2006 (LER 2006-004), Unit 2 experienced a closure of the 1A MSIV while operating at 115 percent of OLTP, which resulted in closure of all MSIVs. All systems responded as required.

Clinton Power Station - 20% Approved EPU (BWR6 with Mark 3 containment)

On July 4, 2002 (LER 2002-003), the Clinton Power Station tripped from 114 percent of OLTP due to a faulty main power transformer sudden pressure relay (SPR) actuation. The SPR initiated a generator trip and lockout. The plant responded as expected to the scram with no safety relief valves lifting during the event. On March 22, 2004 (LER 2004-001), while the plant was operating at approximately 110 percent of OLTP, a generator trip caused a main turbine trip and turbine control valve fast closure, which resulted in an automatic reactor scram. No MSIVs closed and no safety relief valves lifted during the event.

PBAPS Plant-Specific Transient Operating Experience

Another factor used by the licensee in justifying not performing LTT was information from actual plant transients experienced at PBAPS. As documented in Attachment 10 to the EPU LAR, on September 15, 2003, PBAPS, Units 2 and 3, each experienced an MSIV closure event while operating at 100 percent of CLTP for Unit 2, and 90 percent CLTP for Unit 3 (LER 2-03-04). The licensee stated that the event was the result of an interruption of power to the reactor protection system and the primary containment isolation system logic circuits. There were no detrimental effects to the reactor coolant system as a result of the event. Also, since the PBAPS PUSAR (Section 2.2.2.2) indicates that the generic evaluation for MSIV closure, identified in guidance contained in NRC-approved vendor topical report, GE LTR ELTR2 (Section 4.7), is bounding and applicable to PBAPS; and PBAPS is performing a CPPU without a corresponding pressure increase, the licensee does not recommend performance of an MSIV closure test.

The licensee stated in Table 10-2, "Planned EPU Power Ascension Testing," of Attachment 10 to the EPU LAR that a station surveillance test (EPU Test 25) is to be performed on one MSIV at approximately 75 percent of CLTP and other power levels, if necessary, to verify the margins to scram/trip setpoints. On July 22, 2003, a main generator lockout event (Unit 2) produced a reactor scram from 100 percent of CLTP, as a result of a fast closure of the main turbine control valves. All control rods were fully inserted on the reactor scram signal and all safety systems functioned as designed.

A similar event occurred on October 23, 2001 (LER 2-01-004) when Unit 2 experienced an automatic reactor scram from 100 percent of CLTP as a result of a main turbine trip caused by a generator lockout. The LER stated that all isolations performed as designed, no ECCS actuations occurred, and all other systems responded as expected for the given plant conditions. Both events were determined to be bounded by the transient event analysis (generator load rejection with and without bypass) as described in the PBAPS UFSAR Section 14.5.1.

Plant Transient Evaluation

Transient experience at high power and for a wide range of operating power levels at operating BWR plants has shown an acceptable correlation of the plant transient data to the predicted response. The operating history of PBAPS, which includes both a recent MSIV closure event and a generator load rejection event, both initiated at 100 percent of the CLTP level, demonstrates that transient events from full power are within the expected peak limiting values.

The transient analysis performed in support of the proposed EPU demonstrates that all safety criteria are met and that the EPU will not cause any previous non-limiting events to become limiting. The licensee concluded that no new design functions are introduced as part of the EPU that would necessitate LTT validation.

Some instrument setpoints will be changed as part of the EPU, although the NRC staff confirmed that the changes (see Table 2.4-1 of the PUSAR) would not contribute negatively to the response to large transient events. The following two setpoints will be changed that affect MSIV closure: main steam line high flow isolation will be increased from 137.77 percent rated steam flow for CLTP to 140 percent rated steam flow for EPU, and main steam line low pressure isolation will be decreased from 850 pounds per square inch gauge (psig) at CLTP to 825 psig for EPU.

The NRC staff evaluated the setpoint changes and determined that, because the high flow rate setpoint was increased and the low pressure setpoint was decreased, these changes decrease the likelihood of an MSIV closure. Moreover, the staff expects that these minor changes do not substantially affect plant performance under transient conditions, and that the above conclusions continue to apply.

No physical modifications or setpoint changes are made to the pilot-operated SRVs. One new SSV will be installed for EPU to maintain margin to the ASME Code limits during rapid pressurization events analyzed for EPU. The new SSV is the same as the existing two SSVs and has the same setpoint. The licensee stated that the additional SSV does not change the existing functional relationship between the SRVs and the SSVs. It only adds additional pressure relief capacity.

Should any future large transients occur, PBAPS procedures require identification of any anomalous plant response and verification that all key safety-related equipment, required to function during the event, operate as anticipated or expected. Existing plant event data recorders are capable of acquiring the necessary data to confirm the actual versus expected response. In addition, the limiting transient analyses are included as part of the reload licensing analysis.

The generator load rejection and turbine trip events are considered potentially limiting transient events. The response of the reactor and the control systems, following trips of the turbine and generator load rejection, has been demonstrated by numerous plant events, including startup tests at 100 percent of OLTP and operating experience at 100 percent of CLTP. Therefore, the NRC staff determined that a generator load rejection and turbine trip test, as part of the EPU transient testing, is not warranted.

The licensee stated that an MSIV closure event is the limiting transient event with respect to vessel pressurization and relief system capabilities. The response of the reactor and the control systems, following full MSIV closure, has been demonstrated by numerous plant events including startup tests at 100 percent of OLTP and operating experience at 100 percent of CLTP. The licensee also stated that all equipment responses to the MSIV transients were within component and system design capabilities. Based on plant historical data and EPU analytical results, the licensee concluded that the MSIV closure event results in conditions that are within design limits. The NRC staff concludes that MSIV full closure testing, at 100 percent of rated power during EPU power ascension testing, is not necessary at PBAPS because the plant response at EPU conditions is expected to be similar to the documented response during initial startup testing and actual transients that have occurred during plant operation. In addition, limiting transient analyses are included as part of the cycle-specific reload licensing analysis from the licensee.

Based on the above, the NRC staff concludes that the licensee's PATP provides reasonable assurance that plant SSCs that are affected by the proposed EPU will perform satisfactorily in service at the proposed EPU power level. The staff also concludes that the program complies with the quality assurance requirements of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control."

2.12.1.4 SRP 14.2.1, Section III.D, Evaluate the Adequacy of Proposed Testing Plans

SRP 14.2.1, Section III.D specifies that a licensee's EPU LAR should include plans for the initial approach to the increased EPU power level and that steady-state testing 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 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 EPU test program should include the following provisions:

- The initial approach to the uprated EPU power level should be incremental and should include steady-state power hold points to evaluate plant performance above the original full-power level;

- The licensee should propose appropriate testing and acceptance criteria to ensure that the plant responds within design predictions. The predicted responses should be developed 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, not the values of plant conditions used for conservative evaluations of postulated accidents;

- Contingency plans should be implemented in the event the plant does not respond as predicted; and

- The test program should be scheduled and sequenced to minimize the time untested SSCs important to safety are relied upon during operation above the original licensed full-power level. Safety-related SSCs relied upon during operation shall be verified to be operable in accordance with exiting TSs and Quality Assurance Program requirements.

The licensee provided the following information regarding the PBAPS PATP in Section 4.2 of Attachment 10 to the EPU LAR:

- EPU power increases will be made in predetermined increments of less than 5 percent power starting at 90 percent of CLTP so that system parameters can be projected for EPU power before the CLTP level is exceeded. Operating data, including fuel thermal margin, will be taken and evaluated at each step. Routine measurements of reactor and system pressures, flows and vibration will be evaluated for each measurement point, prior to the next power increment.

- Power ascension testing will include appropriate hold points to provide time to assess the plant response, verify test acceptance criteria are met, and verify the test results and plant's operating performance at power levels above CLTP. If all test results are satisfactory, the results will be assembled and presented to the PBAPS Plant Operations Review Committee (PORC) for approval prior to increasing power to the next level. The first review by the PBAPS PORC is required to occur prior to exceeding 100% CLTP with subsequent reviews completed prior to exceeding the next incremental step in power with a final review after reaching 100% EPU power.

- EPU tests will have Level 1 and 2 acceptance criteria. Level 1 criteria are associated with design performance. If a Level 1 test criterion is not met, the plant will be placed in a hold condition that is judged to be satisfactory and safe, based upon prior testing. Resolution of the problem will be immediately pursued by equipment adjustments or through engineering evaluation, as appropriate. The problem resolution plan will be presented to the PORC for approval prior to implementing corrective actions. The applicable test portion will be repeated to verify that the Level 1 requirement is satisfied and the results presented to the PORC for approval prior to increasing reactor power.

- Level 2 criteria are associated with performance expectations. If a level 2 criterion is not met, an evaluation will be initiated to identify the cause and actions necessary to correct the problem. The results of the evaluation will be presented to the PORC for approval prior to implementing corrective actions. If physical adjustments are required, the applicable test portion will be repeated to verify that the Level 2 requirement is satisfied prior to increasing reactor power.

The planned EPU power ascension tests are detailed in Table 10-2 in Attachment 10 to the EPU LAR. These tests supplement the normal TS testing requirements and balance-of-plant monitoring.

The NRC staff reviewed Attachment 10 to the EPU LAR and PUSAR Section 2.12 for conformance with the criteria in SRP 14.2.1, Section III.D. Based on this review, the NRC staff concludes that proposed PATP will adequately assure that the test objectives, test methods, and test acceptance criteria are consistent with the design basis of the plant. Additionally, the staff concludes that the proposed testing will be conducted in an incremental manner, with appropriate hold points for evaluation, and contingency plans would be utilized if the predicted plant response is not obtained.

2.12.1.5 Balance-of-Plant Systems Testing Review

The NRC staff reviewed the licensee's power ascension and testing plan as it related to balance-of-plant (BOP) systems included within the scope of the original PBAPS pre-operational test program or subject to extensive modification to support operation at the EPU power level. With regard to BOP systems, the original pre-operational test program included performance tests for the feedwater system and the turbine bypass system, as well as integrated plant testing (e.g., generator load rejection and turbine trip tests). Licensees commonly modify BOP systems, especially the feedwater system, to support operation at the EPU power level. The NRC staff determined that past plant experience combined with a demonstration of acceptable plant performance during the power ascension test program will provide reasonable assurance that the BOP systems will function as designed. The staff found the licensee's test program and its justification for not performing large transient testing to be acceptable based on the applicable review criteria discussed in Section III.C.2 of SRP 14.2.1.

Conclusion

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. Therefore, the NRC staff finds the proposed EPU test program acceptable.

2.13 Risk Evaluation

2.13.1 Risk Evaluation of EPU

Regulatory Evaluation

The licensee conducted a risk evaluation to: (1) demonstrate that the risks associated with the proposed EPU are acceptable; and (2) determine if "special circumstances" are created by the proposed EPU. As described in Appendix D of SRP Chapter 19.2, "Review of Risk Information Used to Support Permanent Plant-Specific Changes to the Licensing Bases: General Guidance," dated June 2007, special circumstances are present if any issue would potentially rebut the presumption of adequate protection provided by the licensee to meet the deterministic requirements and regulations. The NRC staff's review covered the impact of the proposed EPU on core damage frequency (CDF) and large early release frequency (LERF) for the plant due to changes in the risks associated with internal events, external events, and shutdown operations. In addition, the NRC staff's review covered the quality of the risk analyses used by the licensee to support the application for the proposed EPU. This included a review of the licensee's actions to address issues or weaknesses that may have been raised in previous NRC staff reviews of the licensee's individual plant examinations (IPEs) and individual plant examinations of external events (IPEEE), or by an industry peer review. The NRC's risk acceptability guidelines are contained in RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," Revision 2, dated May 2011. Specific review guidance is contained in Matrix 13 of RS-001 and its attachments.

Technical Evaluation

The licensee provided its risk evaluation of the proposed EPU in Section 2.13 of the PUSAR and in Attachment 12 to the EPU LAR. The licensee did not request the relaxation of any deterministic requirements for their proposed EPU, and the NRC staff's approval is primarily based on the licensee meeting the current deterministic engineering requirements.

The NRC staff's technical review is detailed below in SE Sections 2.13.1.1 through 2.13.1.4. The NRC staff did not identify any issues (i.e., special circumstances) that would rebut the presumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements.

2.13.1.1 Probabilistic Risk Assessment (PRA) Model Quality

The quality of the licensee's PRA used to support a license application needs to be commensurate with the role the PRA results play in the decision-making process. The NRC staff's approval is based on the licensee meeting the current deterministic requirements, with the risk assessment providing confirmatory insights and ensuring that the EPU creates no new vulnerabilities.

IPE/IPEEE

By letter dated August 26, 1992 (Reference 61), the licensee submitted the IPE for PBAPS, Units 2 and 3, in response to NRC Generic letter (GL) 88-20, "Individual Plant Examination for Severe Accident Vulnerabilities," dated November 23, 1988 (Reference 62). The NRC staff's review of the PBAPS IPE is described in an SE dated October 25, 1995 (Reference 63).

By letter dated May 29, 1996 (Reference 64), the licensee submitted the IPEEE for PBAPS, Units 2 and 3, in response to NRC GL 88-20, Supplement 4, "Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities," dated June 28, 1991 (Reference 65). The NRC staff's review of the PBAPS IPEEE is described in an SE dated November 22, 1999 (Reference 66). The staff's SE concluded that the licensee's IPEEE process is capable of identifying the most likely severe accidents and severe accident vulnerabilities.

As discussed in Section 2 of Attachment 12 to the EPU LAR, the licensee stated that the PBAPS IPE and IPEEE submittals were reviewed for identification of vulnerabilities, outliers, anomalies or weaknesses that would impact the PBAPS EPU risk assessment. The licensee stated that IPE submittal noted that no plant vulnerabilities leading to core damage or a large release were uncovered in the IPE process. The licensee further stated that the IPEEE did not identify any vulnerabilities associated with seismic, fire or other external events. The licensee concluded that, based on the review of the IPE and IPEEE submittals, there are no vulnerabilities, outliers, anomalies or weaknesses that would impact the results and conclusions of the PBAPS EPU risk assessment.

PRA Peer Review

As discussed in Section 1.2 of Attachment 12 to the EPU LAR, in November 2010, the BWROG performed a peer review of the PBAPS PRA. The licensee stated that the review was performed using ASME/ANS Standard RA-Sa-2009, "Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications," and RG 1.200, Revision 2.

The BWROG peer review identified 16 Facts and Observations (F&Os) supporting requirements that were assessed as not meeting Capability Category II, as shown in Table A-1 of Appendix A to Attachment 12 to the EPU LAR. The peer review also identified seven other F&Os which were related to the current ANS/ASME PRA Standard for internal events and internal flood associated with supporting requirements that are otherwise met at Capability Category II, as shown in Table A-2 of Appendix A to Attachment 12 to the EPU LAR.

The NRC staff finds that all F&O findings were properly assessed and dispositioned in regard to this application.

Conclusions Regarding the Quality of the PBAPS PRA

The quality of the licensee's PRA used to support a license application needs to be commensurate with the role the PRA results play in the decision-making process. The NRC staff's evaluation did not involve an in-depth review of the licensee's PRA. Instead, it involved an evaluation of the information provided by the licensee in its submittal. As noted above, the licensee stated that a BWROG peer review was conducted on the PBAPS PRA model. The staff reviewed the peer review findings associated with this assessment and finds the internal events PRA model to be adequate to support this application. The internal fire events were addressed using the Fire Induced Vulnerability Evaluation (FIVE) methodology and the seismic evaluations were performed in accordance with the EPRI Seismic Margins Analysis (SMA) methodology.

Based on its evaluation, the NRC staff finds that the PBAPS PRA model used to support the risk evaluation for this application has sufficient scope, level of detail, and technical adequacy to support the evaluation of the EPU.

2.13.1.2 Internal Events Risk Evaluation

The following table summarizes the results of the licensee's risk evaluation as discussed in Section 5.1 of Attachment 12 to the EPU LAR:

Internal Events CDF and LERF Risk Metrics

	Pre-EPU	Post-EPU	Delta Change	Percent increase
Unit 2 CDF[2]	3.6E-06/year	3.70E-06/year	1.0E-07	2.8
Unit 2 LERF	4.58E-07/year	4.74E-07/year	1.6E-08	3.5

The increases in internal events CDF and LERF, shown in the above table, fall within the RG 1.174 acceptance guidelines for being "very small," and therefore do not raise concerns of adequate protection.

The NRC staff finds the licensee's evaluation of the impact of the proposed EPU on at-power risk from internal events is reasonable. The staff concludes that the base risk due to the proposed EPU is acceptable and that there are no issues that rebut the presumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements.

Initiating Event Frequencies

The PBAPS PRA model includes initiating event categories which includes transient initiating events, LOOP, LOCA initiators, support system failures, and internal flooding initiators, as discussed below.

Transients - The licensee stated that the evaluation of the plant conditions and procedural changes for EPU conditions do not result in any new transient initiators, nor directly impact transient initiator frequencies. Sensitivity calculations were performed that increased the transient initiator frequency to bound the various challenges to the BOP side of the plant such as main turbine modifications.

LOOP - The licensee stated in their submittal that no change in the LOOP initiating event frequency is expected. The isolated phase bus duct was modified to accommodate the additional power output, but there is no significant impact on grid stability due to the PBAPS EPU.

LOCA - The licensee did not identify any impact on LOCA or interfacing system LOCA frequencies resulting from the EPU. A sensitivity study concluded that increased flow rates of the EPU can result in increased piping erosion/corrosion rates which increase the LOCA initiating event frequencies including main steam and feedwater line breaks.

Support System - The licensee states that no significant changes to support systems are planned in support of the EPU and no significant impact on support system initiating event frequencies due to the EPU are postulated.

Internal Flooding - The licensee states that since the methodology used in calculating the initiating event frequency for internal flooding is based on the length of piping found within a

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2 Since the base case CDF and LERF are slightly lower for Unit 3 and based on a review of the changes in CDF and LERF for the EPU assessment, the EPU is expected to provide very similar impacts for Unit 3.

system and the fact that the geometry and most of the flow rates associated with the major flooding sources are not changing; there are no substantive changes to other systems that might induce internal flooding. However, since the higher flow rates associated with EPU could have an impact on some of the internal flooding initiating event frequencies, a separate sensitivity evaluation was explored, which conservatively increased all of the internal flood frequencies.

The NRC staff finds the licensee adequately addressed internal initiating event frequencies based on the licensee properly implementing the equipment modifications and replacements it identified in its LAR. Furthermore, sensitivity cases that increase transient initiating event frequencies are quantified in this EPU risk analysis to bound the various changes to the BOP side of the plant and potential operational issues. Finally, the staff notes that no change is being made to the PRA initiating events in the base case analysis as a result of EPU and any changes would be addressed through the licensee's existing plant monitoring programs.

The NRC staff has not identified any issues associated with the licensee's evaluation of internal initiating event frequencies that would significantly alter the overall risk results or conclusions for this LAR. Therefore, the staff concludes that there are no issues with the evaluation of internal initiating event frequencies associated with the PBAPS internal events PRA that would rebut the presumption of adequate protection or warrant denial of this license amendment.

Component Failure Rates

The licensee concluded in its submittal that the EPU would not significantly impact long-term equipment reliability due to the replacement/modification of plant components. The majority of hardware changes in support of the EPU may be characterized as either replacement of components or upgrade of existing components. The licensee described no planned operational modifications as part of the EPU that involve operating equipment beyond design ratings.

The NRC staff finds that the licensee adequately addressed equipment reliability based on the licensee properly implementing the equipment modifications and replacements it identified in its LAR. Further, any short-term risk impact of the numerous BOP equipment changes, due to break-in failures, is expected to be qualified by the current initiating event frequency. Finally, the staff notes that the licensee's component monitoring programs, including equipment modifications and/or replacement are being relied upon to maintain the current reliability of the equipment.

The NRC staff has not identified any issues associated with licensee's evaluation of component reliability that would significantly alter the overall results or conclusions for this license amendment. Therefore, the staff concludes that there are no issues with component reliabilities/failure rates modeled in the PBAPS internal events PRA that would rebut the presumption of adequate protection or warrant denial of this license amendment and that the expectation is that there will be no change in component reliability as a result of the EPU.

Success Criteria

The licensee evaluated the impact of the proposed EPU on PRA success criteria. The PRA success criteria are affected by the increased boil-off rate, the increased heat load to the suppression pool, and the increase in containment pressure and temperature. The success criteria of a mitigation function to an initiator are represented in the PRA models by the availability of a discrete number of systems or trains and the timing differences associated with the performance of specific operator actions. These scenario-specific requirements define the success criteria for system operation and operator action to fulfill the critical safety functions necessary to prevent core damage.

The SRV setpoints were not changed as a result of the EPU; however, the base case probability of a stuck-open SRV due to additional cycling was increased in the PBAPS PRA by 12.5 percent by using the conservative upper bound approach of increasing SRV probability by a factor equal to the increase in reactor power. The approach assumes that the stuck open relief valve probability is linearly related to the number of SRV cycles, and that the number of SRV cycles is linearly related to the reactor power increase. Two additional less conservative approaches were also considered by the licensee: one that considered the number of cycles having a non-linear relationship to reactor power increase, and another that assumed the stuck-open relief valve probability is dominated by the initial cycle and that subsequent cycles have a much lower failure rate.

Timing changes have been identified for the Level 1 PRA and can impact human error probabilities (HEPs) for operator actions. This change has been factored into revised HEP values for EPU conditions, as described below in the section on operator actions.

The licensee noted a negligible impact on the Level 2 PRA safety functions and results and concluded that no changes to the success criteria have been identified with regard to the Level 2 containment evaluation.

The NRC staff concurs with the licensee's changes to the success criteria made to reflect the post-EPU plants.

Operator Actions and LOOP Recovery

An EPU has the general effect of reducing the time available for the operators to complete recovery actions, because of the higher decay heat level after EPU implementation. The plant is dependent on 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 EPU is the time available within which to detect, diagnose, and perform required actions. The higher power levels normally result in reduced time available for some operator actions.

The licensee performed Modular Accident Analysis Program (MAAP) calculations to determine how the operator action timelines were impacted. Afterwards, all post-initiator HEPs in the model were re-calculated using the same human reliability analysis (HRA) methods. One additional action was added to the model related to aligning an RHR cross-tie to two RHR heat exchangers supported by two high pressure service water pumps to allow operation of the pumps with suction from the suppression pool without crediting containment accident pressure. The licensee states that specific control room indications that will be made to support the use of the RHR cross-tie and HPSW cross-connect modifications are subsumed in the human reliability assessment for those actions. In addition to this change, the licensee notes that all updated HEP values are factored directly into the risk assessment. Based on the licensee's submitted information, the NRC staff finds that it is reasonable to expect that the main impact of the EPU is to reduce the time available for some operator actions, which will increase the associated HEPs. However, these increased HEPs are not expected to create significant impacts.

The NRC staff has not identified any issues associated with the licensee's evaluation of operator actions that would significantly alter the overall results or conclusions for this LAR. Therefore, the NRC staff concludes that there are no issues with the operator actions evaluation associated with the PBAPS internal events PRA that would rebut the presumption of adequate protection or warrant denial of this license amendment.

2.13.1.3 External Events Risk Evaluation

The licensee has a limited seismic and fire PRA model. The IPEEE studies used EPRI Fire Induced Vulnerability Evaluation (FIVE) methodology and a seismic margins assessment (SMA) to address external risk from these sources. High winds, external flooding, and transportation and nearby facility accidents were addressed by reviewing the plant environs against regulatory requirements. The licensee provided a qualitative assessment of the impact of EPU implementation on external event risk, which is discussed below.

Internal Fire Risk

For the IPEEE fire analysis, the licensee performed a fire PRA by implementing the FIVE methodology. The IPEEE staff evaluation notes that the licensee has employed proper methodology (i.e., a modified version of EPRI's FIVE methodology) and has used proper data bases for fire occurrence frequencies and for suppression system failure rates. The fire risk evaluation using the EPRI FIVE methodology estimated a fire-induced CDF of 4.38E-5 (delta of 2.5E-7) per year.

In the EPU LAR, the licensee explained that the fire PRA model used in the PBAPS EPU risk assessment is based on the PBAPS IPEEE fire analysis and an update to this analysis (2007) of the main control room and cable spreading room. An update of the PBAPS IPEEE fire model for integration with the latest PBAPS PRA revision was not performed as part of the PBAPS EPU risk assessment. The NRC staff does not expect the use of a prior PRA model to significantly impact the delta risk due to fire for this application. The fire PRA model was estimated for this EPU risk assessment using the same changes incorporated into the internal events PRA. The results of the changes to the PBAPS fire PRA due to the reduced timings available show an increase of less than one percent in the fire CDF.

Since the fire frequencies and fire mitigation are not related to reactor power level, the NRC staff does not expect the post-EPU risk increase due to fire to exceed RG 1.174 guidelines and create the "special circumstances" described in Appendix D of SRP Chapter 19.2 for a non-risk-informed application.

Seismic Risk

The PBAPS seismic risk analysis was performed as part of the IPEEE. Given the PBAPS relatively lower seismic design basis and the relatively higher seismic hazard at the site (as compared to Reduced-Scope Review Level); NUREG-1407 (IPEEE submittal guidance) placed PBAPS in the 0.3g Focused-Scope Review Level Earthquake IPEEE seismic category. Based on the understanding that the licensee used EPRI's SMA in their IPEEE with a modified focused-scoped analysis, the IPEEE SE by NRC staff concluded that there were no major weaknesses identified in the seismic study. The EPU results in additional thermal energy stored in the reactor pressure vessel (RPV), but the additional blowdown loads on the RPV and containment, given a coincident seismic event, are judged not to alter the results of the SMA. The decrease in time available for operator actions, and the associated increases in calculated HEPs is judged not have a significant impact on seismic-induced risk. As such, the NRC staff does not expect the seismic risk associated with the plant to rebut the presumption of adequate protection. For a risk-informed submittal, the staff would have investigated further the impact of seismic risk; however, for a submittal that is not risk-informed, the staff does not expect the post-EPU risk to significantly increase due to seismicity and create the "special circumstances" described in Appendix D of SRP Chapter 19.2.

Other External Events Risk

The PBAPS IPEEE addresses events other than seismic and fires, including high winds/tornadoes, external floods, and transportation and nearby facility accidents. Consistent with the IPEEE guidance, the licensee reviewed the plant environs against regulatory requirements regarding these hazards and concluded that PBAPS meets the applicable NRC SRP requirements and, therefore, has an acceptably low risk with respect to these hazards.

External Events Risk Conclusion

The NRC staff has not identified any issues associated with the licensee's evaluation of the risks related to external events that would significantly alter the overall results or conclusions for this LAR. Therefore, the NRC staff concludes that there are no issues with the external events risk evaluation that would rebut the presumption of adequate protection or warrant denial of this license amendment. The expectation is that the risk impact from external events resulting from the proposed EPU will be very small, based on the licensee's current risk evaluations.

2.13.1.4 Shutdown Risk Evaluation

The primary impact of the EPU on risk during shutdown operations is associated with the decrease in allowable operator action times in response to "off-normal" events. The aspects of shutdown risk that the licensee identified as being impacted by EPU conditions included shutdown post-initiator HEPs, offsite AC recovery failure probabilities, and decay heat removal systems success criteria. All of these aspects result from the reduction in times to core damage created by the EPU. The increased power level decreases the time to core damage due to boil off. However, because the reactor is already shut down, the boil off times are relatively long and increase relative to the number of days following reactor shutdown.

The licensee stated computerized risk monitors (PARAGON) and site-specific management guidelines are in place to ensure the risk impacts of EPU on shutdown operations are not significant and that requirements of NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management" are implemented to assure risk is assessed and that structures, systems, and components that perform key safety functions are available when needed.

The change in offsite AC recovery failure probabilities for EPU will potentially result in a reduced required time to restore power before core damage. The licensee's submittal contains time to boil numbers in hours. These values were updated for EPU conditions. Tables B-2 to B-4 in Appendix B to Attachment 12 to the EPU LAR show the estimated times to core damage, due to boil off, based on different initial RPV water levels. These values trend upward for available time to core damage the longer the outage lasts.

Based on review of the potential impacts on initiating events, success criteria, and HRA, the EPU is assessed to have a negligible impact on shutdown risk. The licensee approximates one percent per the calculations in Appendix B to Attachment 12 to the EPU LAR.

The NRC staff has not identified any issues associated with the licensee's evaluation of shutdown risks that would significantly alter the overall results or conclusions for this LAR. Therefore, the NRC staff concludes that there are no issues with the shutdown operations risk evaluation that would rebut the presumption of adequate protection or warrant denial of this license amendment. The expectation is that the impact on shutdown risk resulting from the proposed EPU will be negligibly small, based on the licensee's current shutdown risk management process.

Conclusion

The NRC staff has reviewed the licensee's assessment of the risk implications associated with the implementation of the proposed EPU and concludes that the licensee has adequately modeled and/or addressed the potential impacts associated with the implementation of the proposed EPU. The NRC staff further concludes that the results of the licensee's risk analysis indicate that the risks associated with the proposed EPU are acceptable and do not create the "special circumstances" described in Appendix D of SRP Chapter 19.2. 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 Licenses (FOLs) and Technical Specifications for PBAPS, Units 2 and 3. The proposed changes are shown in Attachment 2 to the EPU LAR (Reference 1), as modified by the following supplements to the EPU LAR: Attachment 2 to Supplement 5 dated June 27, 2013 (Reference 6); Attachment 3 to Supplement 16 dated December 20, 2016 (Reference 17); Attachment 6 to Supplement 17 dated January 17, 2014 (Reference 18); Attachment 3 to Supplement 26 dated May 6, 2014 (Reference 114), Attachment 2 to Supplement 27 dated June 5, 2014 (Reference 116), and Supplement 28 dated June 20, 2014 (Reference 117).

3.1 FOL Paragraph 2.C(1) - Maximum Power Level

FOL Paragraph 2.C(1), "Maximum Power Level" would change the maximum authorized steady state reactor core power level from the CLTP level of 3514 MWt to the proposed EPU power level of 3951 MWt. This change reflects the proposed approximate 12.4% increase in thermal power level and is consistent with the licensee's supporting safety analyses. Therefore, the NRC staff concludes that the proposed change to FOL Paragraph 2.C(1) is acceptable.

3.2 TS 1.1 - Rated Thermal Power Definition

The TS 1.1 Definition for "RATED THERMAL POWER" would be revised to change the rated thermal power (RTP) level from the CLTP level of 3514 MWt to the proposed EPU power level of 3951 MWt. This change reflects the proposed approximate 12.4% increase in thermal power level and is consistent with the licensee's supporting safety analyses. Therefore, the NRC staff concludes that the proposed change to TS 1.1 is acceptable.

3.3 TS 2.1.1 - Reactor Core Safety Limits

TS 2.1.1 currently provides the following reactor core safety limit (SL) when the reactor steam dome pressure is less than 785 psig or the core flow is less than 10% rated core flow:

> THERMAL POWER shall be ≤ 25% RTP.

The proposed amendment would change the SL from 25% to 23% RTP.

As discussed in Section 2.8.2.1.2 of the PUSAR:

> The CLTR states that the percent power level above which fuel thermal margin monitoring is required may change with EPU. The original plant operating licenses set this monitoring threshold at a typical value of 25% of rated thermal power (RTP). [[
>
>]]
>
> For EPU, as specified in the CLTR, the fuel thermal margin monitoring threshold is scaled down, if necessary, to ensure that monitoring is initiated [[
>
>]] then the existing power threshold value must be lowered by a factor of $1.2/P_{25}$.

> For PBAPS, the fuel thermal monitoring threshold is established at 23% of EPU RTP ((1.2 MWt/bundle) * (764 bundles / 3951 MWt)) = 23%). A change in the fuel thermal monitoring threshold also requires a corresponding change to the TS reactor core safety limit for reduced pressure or low core flow.

Since the revised SL is based on [[
]], the analysis is bounding for PBAPS. Therefore, the NRC staff concludes that the proposed change to TS 2.1.1 is acceptable.

3.4 TS 3.1.7 - Standby Liquid Control System

Surveillance Requirement (SR) 3.1.7.1

SR 3.1.7.1 for the standby liquid control (SLC) system currently requires that the level of sodium pentaborate solution in the SLC tank is verified to be greater than or equal to 46%. The proposed amendment would change the minimum level to 52%.

As discussed in Section 3.1.4 of Attachment 1 to the EPU LAR and in UFSAR Section 3.8.1, the PBAPS Alternative Source Term (AST) licensing basis relies upon the SLC system injecting the sodium pentaborate solution contents from the SLC tank into the reactor pressure vessel to maintain the suppression pool pH ≥ 7.0 post-LOCA. Maintaining suppression pool pH ≥ 7.0 post-LOCA prevents the radioactive iodine from re-evolving, which maintains offsite and control room doses below the 10 CFR 50.67 limits.

The licensee stated that the sodium pentaborate solution acts as a buffer in the suppression pool to inhibit the decrease in suppression pool pH due, in part, to the radiolysis of chlorinated polymer cable jacketing. Additional lengths of similar jacketed cable are planned to be installed in the Units 2 and 3 drywells as part of the planned EPU. As such, the licensee determined that the current SLC tank minimum level needed to be increased from 46% to 52% in order to provide sufficient margin to ensure that suppression pool pH is maintained ≥ 7.0 following a LOCA.

The NRC staff concludes that the proposed change to TS 3.1.7 is acceptable since it is intended to maintain the current AST licensing basis assumption regarding maintaining suppression pool pH ≥ 7.0 post-LOCA.

SRs 3.1.7.5, 3.1.7.7, 3.1.7.8 and 3.1.7.10; Table 3.1.7.1; and Figure 3.1.7-1

SR 3.1.7.5 currently reads as follows:

> Verify the concentration of boron in solution is ≤ 9.82% weight and within the limits of Table 3.1.7.1.

The proposed amendment would change SR 3.1.7.5 to read as follows:

> Verify the concentration of boron in solution is ≥ 8.32% weight and ≤ 9.82% weight.

SR 3.1.7.8[3] currently reads as follows:

> Verify each pump develops a flow rate ≥ 43.0 gpm at a discharge pressure ≥ 1275 psig.

The proposed amendment would change SR 3.1.7.8 to read as follows:

> Verify each pump develops a flow rate ≥ 49.1 gpm at a discharge pressure ≥ 1275 psig.

SR 3.1.7.10 currently reads as follows:

> Verify sodium pentaborate atom percent B-10 enrichment is within the limits of Table 3.1.7.1.

The proposed amendment would change SR 3.1.7.10 to read as follows:

> Verify sodium pentaborate enrichment is ≥ 92.0 atom percent B-10.

Table 3.1.7.1 currently provides an equivalency equation, which combines SLC system boron concentration, SLC pump flow rate, and B-10 enrichment, in order to result in reactivity control for an anticipated transient without scram (ATWS) event consistent with the requirements in 10 CFR 50.62(c)(4). The proposed amendment would delete this table.

Figure 3.1.7-1 provides a graph of sodium pentaborate solution temperature versus concentration. As discussed in the TS Bases, this figure ensures that a 10 °F margin will be maintained above the saturation temperature so that boron does not precipitate out of solution in the storage tank or in the pump suction piping due to low boron solution temperature (below the saturation temperature for the given concentration). The proposed amendment would revise the figure to show the minimum concentration of ≥ 8.32% weight that would be incorporated into SR 3.1.7.5 and to more clearly depict the "not acceptable" area for maintaining sodium pentaborate concentrations.

As discussed in Section 3.1.4 of Attachment 1 to the EPU LAR, the equivalency equation in Table 3.1.7.1 would no longer reflect the PBAPS design basis following the EPU. Therefore, the equivalency equation is being replaced (i.e., deletion of Table 3.1.7-1) with specific limits, for EPU conditions, in SR 3.1.7.5, SR 3.1.7.8, SR 3.1.7.10, and Figure 3.1.7-1. The NRC staff finds that the proposed changes will provide clearer direction to the plant operations staff in maintaining the associated SLC system parameters (i.e., versus the current equivalency table

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3 The marked-up TS pages shown in Attachment 2 to the EPU LAR (Reference 1), request to change the SLC pump discharge pressure in SR 3.1.7.8 from "1255 psig" to "1265 psig." However, on May 5, 2014, the NRC staff issued Amendment Nos. 290 and 293 for PBAPS Units 2 and 3, respectively (Reference 115), that revised the TSs to: (1) increase the allowable as-found SRV and SV lift setpoint tolerance from ± 1% to ± 3%; (2) increase the required number of operable SRVs and SVs from 11 to 12; and (3) increase the SLC system pump discharge pressure from 1255 psig to 1275 psig. In Supplement 27 to the EPU LAR (Reference 116), Exelon withdrew the request to change the SLC pump discharge pressure to 1265 psig (i.e., the SR 3.1.7.8 value will remain as 1275 psig).

method). In addition, the NRC staff finds that the proposed changes will continue to ensure proper balance of boron concentration, SLC pump flow, and B-10 enrichment consistent with the requirements in 10 CFR 50.62(c)(4). Based on these findings, the NRC staff concludes that the proposed changes to SR 3.1.7.5, SR 3.1.7.8, SR 3.1.7.10, and Figure 3.1.7-1, and the proposed deletion of Table 3.1.7.1 are acceptable.

In addition to the above SLC system TS changes, the proposed amendment would delete SR 3.1.7.7. This SR currently requires verification of the minimum quantity of B-10 stored in the SLC tank in pounds mass. As discussed in Section 3.1.4 of Attachment 1 to the EPU LAR, this SR would be redundant to the proposed change to SR 3.1.7.10 for minimum required boron enrichment in combination with SR 3.1.7.1 for minimum tank level and SR 3.1.7.5 and Figure 3.1.7-1 for minimum sodium pentaborate concentration. The NRC staff finds that the combination of the required parameters per the proposed amendment would replace the need to verify the mass of B-10 stored in the SLC tank. Therefore, the NRC staff concludes that the proposed deletion of SR 3.1.7.7 is acceptable.

In addition to the changes discussed above regarding verification of the sodium pentaborate enrichment in SR 3.1.7.10, the proposed amendment would change the frequency for performance of SR 3.1.7.10. Currently, the surveillance frequency is "Once within 8 hours after addition to the SLC tank." The proposed amendment would change the frequency to read as follows:

> In accordance with the Surveillance Frequency Control Program
>
> AND
>
> Once within 8 hours after addition to the SLC tank.

The Surveillance Frequency Control Program is described in TS 5.5.14. The NRC staff finds that performance of the SR in accordance with the program and within 8 hours after addition of sodium pentaborate to the tank provides reasonable assurance that the SLC tank enrichment will be maintained within limits to assure the associated LCO will be met. Therefore, the NRC staff concludes that the proposed change to the SR 3.1.7.10 frequency is acceptable.

3.5 TS 3.2.1 - Average Planar Linear Heat Generation Rate

The TS 3.2.1 Limiting Condition for Operation (LCO) Applicability, LCO Required Action B.1, and SR 3.2.1.1 Frequency include requirements associated with a thermal power limit of 25%. The proposed amendment would change "25% RTP" value to "23% RTP" in all 3 instances.

As discussed in Section 3.1.5 of Attachment 1 to the EPU LAR, these proposed changes are based on the fuel thermal limit monitoring threshold discussed in Section 2.8.2.1.2 of the PUSAR.

Based on the discussion in SE Section 3.3, the NRC staff concludes that the proposed changes to TS 3.2.1 are acceptable.

3.6 TS 3.2.2 - Minimum Critical Power Ratio

The TS 3.2.2 LCO Applicability, LCO Required Action B.1, and SR 3.2.2.1 Frequency include requirements associated with a thermal power limit of 25%. The proposed amendment would change "25% RTP" value to "23% RTP" in all 3 instances.

As discussed in Section 3.1.6 of Attachment 1 to the EPU LAR, these proposed changes are based on the fuel thermal limit monitoring threshold discussed in Section 2.8.2.1.2 of the PUSAR.

Based on the discussion in SE Section 3.3, the NRC staff concludes that the proposed changes to TS 3.2.2 are acceptable.

3.7 TS 3.2.3 - Linear Heat Generation Rate

The TS 3.2.3 LCO Applicability, LCO Required Action B.1, and SR 3.2.3.1 Frequency include requirements associated with a thermal power limit of 25%. The proposed amendment would change "25% RTP" value to "23% RTP" in all 3 instances.

As discussed in Section 3.1.7 of Attachment 1 to the EPU LAR, these proposed changes are based on the fuel thermal limit monitoring threshold discussed in Section 2.8.2.1.2 of the PUSAR.

Based on the discussion in SE Section 3.3, the NRC staff concludes that the proposed changes to TS 3.2.2 are acceptable.

3.8 TS 3.3.1.1 - Reactor Protection System Instrumentation

3.8.1 TS 3.3.1.1 Changes Related to the Turbine First Stage Pressure Function

The following requirements in TS 3.3.1.1 relate to the turbine first stage pressure function:

- LCO Required Action E.1
- SR 3.3.1.1.13
- Table 3.3.1.1-1, Function 8, Turbine Stop Valve-Closure
- Table 3.3.1.1-1, Function 9, Turbine Control Valve Fast closure, Trip Oil Pressure-Low

Each of the above requirements currently specifies a value of 29.5% RTP (e.g., as a thermal power level at which the requirement applies or a thermal power level the plant must be reduced to under certain conditions). The proposed amendment would change the 29.5% RTP value, for each of the above TSs, to 26.7% RTP.

As discussed in PUSAR Section 2.4.1.3.2, the EPU results in an increased power level, and the high pressure turbine modifications result in a change to the relationship of turbine first-stage pressure to reactor power level. The turbine first-stage pressure setpoint is used to reduce scrams and recirculation pump trips at low power levels where the turbine steam bypass system is effective for turbine trips and generator load rejections. In the safety analysis, this trip bypass only applies to events at low power levels that result in a turbine trip or load rejection. [[

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Attachment 1 to the application dated September 28, 2012, states, for the above TSs, that the 26.7% RTP value is based on rescaling "from the current analytical value of 30% reduced by the percent power increase for EPU" (i.e., 30% x (3514 MWt / 3951 MWt) = 26.7%). Since the approach used in modifying the TS values is consistent with the licensee's supporting safety analyses, the NRC concludes that the proposed change is acceptable.

3.8.2 TS 3.3.1.1 Changes Related to the Oscillation Power Range Monitor (OPRM)

The proposed amendment would make three changes to TS 3.3.1.1 related to the OPRM. The specific TS requirements are as follows:

- Table 3.3.1.1-1, Function 2.f, OPRM Upscale
- LCO Required Action J.1
- SR 3.3.1.1.19

As discussed in the PBAPS UFSAR Section 7.5.7 and the PBAPS TS Bases, the average range power monitor (APRM) channels provide the primary indication of neutron flux within the core. The APRM channels receive input signals from the local power range monitors (LPRMs) within the reactor core to provide an indication of the power distribution and local power changes. Each APRM also includes an OPRM Upscale function that monitors small groups of LPRM signals to detect thermal-hydraulic instabilities.

The OPRM is designed to detect the onset of reactor core power oscillations resulting from thermal-hydraulic instability and suppress them by initiating a reactor scram via the reactor protection system trip logic. The OPRM Upscale function provides protection of the minimum critical power ratio (MCPR) safety limit.

As discussed in the TS Bases, currently the OPRM Upscale trip is automatically enabled (bypass removed) when thermal power is ≥ 29.5% RTP and reactor core flow is < 60% of rated flow. This is the operating region on the power/flow map where actual thermal-hydraulic instability and related neutron flux oscillations may occur. These setpoints establish the boundaries of the OPRM Upscale trip-enabled region.

As described in the TS Bases, currently, the OPRM Upscale function is required to be operable when the plant is at ≥ 25% RTP. The 25% RTP level was selected to provide margin in the event that a reactor power increase transient, occurring while the plant is operating below the auto-enable setpoint of 29.5% RTP, causes a power increase up to or beyond the auto-enable setpoint. This operability requirement assures that the OPRM Upscale trip auto-enable function will be operable when required.

TS Table 3.3.1.1-1, Function 2.f, addresses the power level applicable for when the OPRM Upscale function needs to be operable. As discussed in Supplement 5 to the EPU LAR (Reference 6), for the proposed EPU, the licensee requested that the power level for Function

2.f be changed from ≥ 25% RTP to ≥ 23% RTP. The evaluation of this proposed change is discussed below.

TS 3.3.1.1 Required Action J.1 requires that thermal power be reduced to a power level at which the OPRM Upscale function is not applicable. As discussed in Supplement 5 to the EPU LAR (Reference 6), for the proposed EPU, the licensee requested that the power level be changed from < 25% RTP to < 23% RTP. The evaluation of this proposed change is discussed below.

SR 3.3.1.1.19 establishes the OPRM trip auto-enable setpoint. Currently the SR states "Verify OPRM is not bypassed when APRM Simulated Thermal Power is ≥ 29.5% RTP and recirculation drive flow is < 60%". As discussed in Section 3.1.8 of Attachment 1 to the EPU LAR, the proposed amendment would change the 29.5% auto-enable setpoint to 26.2%. The rescaling from 29.5% RTP to 26.2% RTP maintains the same absolute thermal power level that was evaluated and authorized for CLTP (i.e., 29.5% x (3514 MWt / 3951 MWt)). Since the approach used in modifying the TS value is consistent with the licensee's supporting safety analyses, the NRC concludes that the proposed change is acceptable.

As discussed in Section 4.1 of Attachment 1 of Supplement 5 to the EPU LAR (Reference 6), the EPU LAR (Reference 1) originally proposed to change the values for the OPRM Upscale function (i.e., Table 3.3.1.1-1, Function 2.f and Required Action J.1) from 25% RTP to 21.2% RTP. However, the licensee subsequently, in Reference 6, proposed that the OPRM Upscale function power level be changed to 23% RTP (i.e., instead of 21.2% RTP).

As discussed in Section 4.2 of Attachment 1 of Supplement 5 to the EPU LAR (Reference 6), , instead of the generic evaluation criteria originally used to establish the OPRM TS values in the EPU LAR (Reference 1), the licensee implemented a plant-specific analysis in accordance with generic evaluations described in GE LTR, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function," NEDC-32410P-A Supplement 1, dated November 1997. The GE topical report establishes nominal thresholds for the operability of the OPRM Upscale function and the trip auto-enable setpoint, but it also states that the value for a plant can be established based on plant-specific analysis and setpoint considerations.

As discussed above, currently, the OPRM Upscale trip is automatically enabled when thermal power is ≥ 29.5% RTP. The current auto-enable setpoint is 4.5% above the OPRM Upscale operability threshold for the system (i.e., 29.5% RTP - 25% RTP). During the evaluation of the proposed EPU, as documented in the PUSAR, the licensee used the generic evaluation criteria found in NEDC-32410P-A Supplement 1. That approach resulted in a 5% margin between these parameters, as originally proposed in the EPU LAR (i.e., 26.2% RTP - 21.2% RTP). The plant-specific approach, discussed in Reference 6, would result in a 3.2% margin between these parameters (i.e., 26.2% RTP - 23% RTP).

In order to demonstrate the acceptability of the revised margin of 3.2%, the licensee performed a plant-specific evaluation to identify the expected impact of credible transients that could occur at low power and result in uncontrolled power increases without operator action. The licensee concluded that the loss of feedwater heater (LFWH) transient is the only significant event that could potentially raise the reactor power into the region of anticipated oscillations without operator action.

The licensee determined the power level increase that would be expected due to such an event. Considering normal feedwater temperatures and operation at power levels up to 23% RTP, the licensee concluded that an LFWH event could result in a feedwater temperature reduction of up to 43 °F. This lower feedwater temperature could result in a power increase in the core with a magnitude of about 1.5% power. The resulting increase (to 24.5% RTP) remains below the point at which the OPRM trip is required to be enabled (26.2% RTP). Thus, an OPRM Upscale function operable threshold value of ≥ 23% RTP provides adequate margin.

Based on review of the information in Section 4.0 of Attachment 1 of Supplement 5 to the EPU LAR (Reference 6), the NRC staff finds that the proposed 23% RTP value for the OPRM Upscale function provides adequate margin such that there is reasonable assurance that no credible event could result in an uncontrolled power excursion into a region where significant power oscillations could occur. Therefore, the NRC staff concludes that the proposed changes to TS Table 3.3.1.1-1, Function 2.f and TS 3.3.1.1, Required Action J.1 are acceptable.

The proposed change will also align the operability requirement of the OPRM Upscale function with the requirement for calibration of the APRM per SR 3.3.1.1.2, and the power levels at which fuel thermal margin monitoring is initiated (SR 3.2.1.1, SR 3.2.2.1, and SR 3.2.3.1). The evaluation for these changes is discussed below.

3.8.3 TS 3.3.1.1 Changes Related to the APRM Calibration

As discussed in the TS Bases, to ensure that the APRMs are accurately indicating the true core average power, the APRMs are calibrated to the reactor power calculated from a heat balance. SR 3.3.1.1.2 currently requires this calibration be done when thermal power is ≥ 25% RTP. The proposed amendment would change the "25% RTP" value to "23% RTP" in 2 places in this SR.

As discussed in Section 3.1.8 of Attachment 1 to the EPU LAR, these proposed changes are based on the fuel thermal limit monitoring threshold discussed in Section 2.8.2.1.2 of the PUSAR.

Based on the discussion in SE Section 3.3, the NRC staff concludes that the proposed changes to SR 3.3.1.1.2 are acceptable.

3.8.4 TS 3.3.1.1 Changes Related to APRM Simulated Thermal Power – High Allowable Value

Table 3.3.1.1-1, Function 2.b, and its associated Table 3.3.1.1-1, note (b), contain requirements for the APRM Simulated Thermal Power - High function. This function, also referred to as the APRM flow-biased scram, currently has the following allowable values (AVs) as shown in the TS Table 3.3.1.1-1:

Two loop operation: $\leq 0.65\ W + 63.7\%$ RTP

Single loop operation: $0.65\ (W - \Delta W) + 63.7\%$ RTP

As shown in UFSAR Table 7.5.4, "Average Power Range Monitor Trips," "W" is the recirculation loop flow rate in percent of the design rating and "ΔW" is the difference between two loop and single loop recirculation loop flow at the same core flow.

The proposed amendment would revise the AVs to be as follows:

Two loop operation: ≤ 0.55 W + 63.3% RTP

Single loop operation: 0.55 (W - ΔW) + 61.5% RTP

As discussed in PUSAR Section 2.4.1.3.3, the APRM flow-biased scram settings are being revised due to the increased reactor power level at EPU conditions. The PUSAR further stated that the PBAPS TS AVs for this function are being revised based on the methodology outlined in the CLTR (Reference 20). The licensee provided the calculation for the APRM flow-biased scram function in Enclosure 14a to Attachment 14 of the EPU LAR.

Section 5.2 of the NRC staff's SE for the CLTR, in part, evaluated the proposed CPPU LTR methods for modifying RPS instrument trip setpoints and AVs. The staff found that the instrument setpoint methodology was acceptable for CPPU EPUs. Since the PBAPS APRM flow-biased scram AVs were calculated based on an NRC-approved methodology, the staff concludes that the proposed changes are acceptable.

As shown in Attachment 6 to Supplement 17 to the EPU LAR, the proposed amendment would also add the following 2 notes to Table 3.3.1.1-1 associated with Function 2.b:

(e) If the as-found channel setpoint is outside its predefined as-found tolerance, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.

(f) The instrument channel setpoint shall be reset to a value that is within the Leave Alone Zone (LAZ) around the Nominal Trip Setpoint (NTSP) at the completion of the surveillance; otherwise, the channel shall be declared inoperable. Setpoints more conservative than the NTSP are acceptable provided the as-found tolerance and LAZ apply to the actual setpoint implemented in the Surveillance procedures to confirm channel performance. The NTSP methodologies used to determine the as-found tolerance and the LAZ are specified in the Bases associated with the specified function.

As discussed in Section 3.1.8 of Attachment 1 to the EPU LAR, the above notes were added in accordance with Attachment A of Technical Specification Task Force (TSTF) change traveler TSTF-493, Revision 4, "Clarify Application of Setpoint Methodology for LSSS [Limiting Safety System Settings] Functions" (ADAMS Accession No. ML101160026). The NRC approved TSTF-493 for use as discussed in a *Federal Register* notice dated May 11, 2010 (75 FR 26294). The licensee indicated that the proposed notes were modified slightly from those shown in TSTF-493 to use PBAPS terminology.

The NRC staff has reviewed the proposed changes and finds them consistent with those approved by the NRC in TSTF-493. Therefore, the NRC staff concludes that the proposed new notes to be added to Table 3.3.1.1-1 are acceptable.

3.9 TS 3.3.2.2 - Feedwater and Main Turbine High Water Level Trip Instrumentation

The TS 3.3.2.2 LCO Applicability and LCO Required Action C.2 include requirements associated with a thermal power limit of 25%. The proposed amendment would change "25% RTP" value to "23% RTP" in both instances.

As discussed in Section 3.1.9 of Attachment 1 to the EPU LAR, these proposed changes are based on the fuel thermal limit monitoring threshold discussed in Section 2.8.2.1.2 of the PUSAR.

Based on the discussion in SE Section 3.3, the NRC staff concludes that the proposed changes to TS 3.3.2.2 are acceptable.

3.10 TS 3.3.4.2 - End of Cycle Recirculation Pump Trip Instrumentation

The following requirements in TS 3.3.4.2 relate to the turbine first stage pressure function:

- LCO Applicability
- LCO Required Action C.2
- SR 3.3.4.2.4

Each of the above requirements currently specifies a value of 29.5% RTP (e.g., as a thermal power level at which the requirement applies or a thermal power level the plant must be reduced to under certain conditions). The proposed amendment would change the 29.5% RTP value, for each of the above TSs, to 26.7% RTP.

Based on the discussion in SE Section 3.8.1, the NRC staff concludes that the proposed changes to TS 3.3.4.2 are acceptable.

3.11 TS 3.3.5.1- Emergency Core Cooling System Instrumentation

TS Table 3.3.5.1-1, "Emergency Core Cooling System Instrumentation," Function 3.e, "Suppression Pool Water Level - High," currently specifies an AV of "≤ 5.0 inches above torus midpoint." The proposed amendment would change the AV to read "≤ 16 ft 7 inches."

As discussed in Section 3.1.11 of Attachment 1 to the EPU LAR, the torus midpoint is 15 feet, 6 inches. Therefore, the current AV of 5.0 inches above torus midpoint equates to a level of 15 feet, 11 inches. The licensee stated that the proposed change to the AV is based on modifications and safety analysis assumption changes which increase the ECCS pump NPSH margin and eliminate the reliance on containment accident pressure (CAP) credit in the licensing basis.

Enclosure 9e to Attachment 9 of the EPU LAR provides a discussion of the specific modifications and the licensee's analysis associated with the change to the high suppression pool water level AV. Corrections to the information provided in Attachment 9 to the EPU LAR, was provided in Attachment 8 to the licensee's Supplement 1 dated February 15, 2013 (Reference 2).

Both PBAPS units have a setpoint for swap over of the high pressure coolant injection (HPCI) pump suction from the condensate storage tank (CST) to the suppression pool prior to the high suppression pool water level AV being reached. When the high level swap over setpoint is reached, HPCI suction automatically transfers from the CST to the suppression pool.

Enclosure 9e to Attachment 9 of the EPU LAR provided the following discussion regarding the design basis for the high suppression pool water level AV:

> Excessively high suppression pool water could affect pressure suppression capability and SRV [safety relief valve] tail pipe limits. The Maximum Pressure Suppression Primary Containment Water Level (MPSPCWL) is the highest containment water level at which the pressure suppression capability of the containment can be maintained. Above this level, the pressure suppression capability of the Primary Containment may be insufficient to accommodate the energy released to containment from either a RPV [reactor pressure vessel] blowdown or an RPV breach by core debris. Current procedures define the SRV tail pipe level limit to be the highest suppression pool water level at which opening an SRV will not result in exceeding the capability of the SRV tail pipe, tail pipe supports, quencher, or quencher supports. Damage to these components can lead to inability to use the SRVs or can lead to direct pressurization of the primary containment without pressure suppression. The SRV tail pipe level limit is a curve that is truncated at the suppression pool level that corresponds to the MPSPCWL. The MPSPCWL and tail pipe limit is 17.1 feet. Therefore, signals indicating high suppression pool water level are used to transfer the suction source of HPCI from the CST to the suppression pool to eliminate the possibility of HPCI continuing to provide additional water from a source outside containment. To prevent losing suction to the pump, the suction valves are interlocked so that the suppression pool suction valves must be open before the CST suction valve automatically closes.
>
> The high suppression pool water level signals are initiated from two level switches. The logic is arranged such that either switch can cause the suppression pool suction valves to open and the CST suction valve to close. The Allowable Value (AV) for the TS "Suppression Pool Water Level - High" Function is chosen to ensure that HPCI will be aligned for suction from the suppression pool to prevent HPCI from contributing to any further increase in the suppression pool level.

As discussed in Attachment 8 to the licensee's Supplement 1 dated February 15, 2013, following EPU, the ATWS, Appendix R event, and Station Blackout analysis will rely solely on the CST rather than the suppression pool for the HPCI system suction source for the duration of the events. As discussed in Enclosure 9e to Attachment 9 of the EPU LAR, of these events, the Appendix R event (Shutdown Method B1) would result in the maximum suppression pool water level under EPU conditions. Specifically, Appendix R Shutdown Method B1 analysis for EPU assumes no reliance on CAP credit and results in a maximum suppression pool level of 16.5 feet (16 feet, 6 inches).

Pump suction for HPCI is normally aligned to the CST. As discussed in Enclosure 9e to Attachment 9 of the EPU LAR, both the swap over setpoint and the TS AV must be changed to prevent swap over from the CST to the suppression pool suction prior to the required Appendix R CST volume being transferred by HPCI and to prevent exceeding the TS value. The new setpoint is selected to prevent prematurely switching the suction source of HPCI from the CST to the suppression pool, yet remain below the TS "Suppression Pool Water Level - High" AV.

The current TS AV for "Suppression Pool Water Level - High" is 5 inches above the suppression pool midpoint of 15 feet, 6 inches, which is a level of 15 feet, 11 inches. To prevent premature swap over of the HPCI suction, the licensee proposes to raise the AV to ≤ 16 feet, 7 inches. The plant instrument setpoint will be set below the new TS AV but above 16.5 foot level from the Appendix R Shutdown Method B1 analysis.

The NRC staff concludes that the proposed change to the Suppression Pool Water Level - High AV is acceptable since it provides reasonable assurance that the CST will provide the necessary volume of water for the Appendix R event while also maintaining suppression pool water level below the Maximum Pressure Suppression Primary Containment Water Level.

3.12 TS 3.3.6.1 - Primary Containment Isolation Instrumentation

The proposed amendment would make two changes to TS Table 3.3.6.1-1, "Primary Containment Isolation Instrumentation," as described below.

Main Steam Line Pressure - Low

TS Table 3.3.6.1-1, Function 1.b, "Main Steam Line Pressure - Low," currently specifies an AV of "≥ 850.0 psig." The proposed amendment would change the AV to read "≥ 825.0 psig."

As discussed in the Bases for TS 3.3.6.1, the primary containment isolation instrumentation automatically initiates closure of appropriate primary containment isolation valves (PCIVs). The function of the PCIVs, in conjunction with other accident mitigation systems, is to limit fission product release during and following postulated design-basis accidents. Low main steam line (MSL) pressure indicates there may be a problem with the turbine pressure regulation, which could result in a low reactor water level condition and the RPV cooling down more than its design rate of change if the pressure loss is allowed to continue. The MSL pressure - low function is directly assumed in the analysis of the pressure regulator failure event, which is discussed in UFSAR Section 14.5.4.1. For this event, the closure of the main steam isolation valves (MSIVs) (which is initiated by the MSL pressure - low function) ensures that the RPV temperature change limit (100 °F /hour) is not reached.

As discussed in Section 3.1.12 of Attachment 1 to the EPU LAR, the purpose of the proposed change is to recover operational margin that would be reduced as a result of EPU conditions. The change is intended to minimize the likelihood of MSL low pressure isolations and resultant scrams during pressure transients.

As discussed in Section 3.1.12 of Attachment 1 to the EPU LAR, the licensee stated that the impact of EPU conditions on the main steam and turbine control systems was analyzed. The licensee determined that the steam pressure drop between the reactor and main turbine inlet increases and results in a reduction in margin between the operating main steam pressure and the MSL isolation trip setpoint. As such, a new trip setpoint will be established to recover the operational margin. A change to the AV is required to implement the trip setpoint change.

As discussed in UFSAR Section 7.3.4.7, the trip setpoint is selected far enough below turbine inlet pressures to avoid spurious isolation, yet high enough to provide timely detection of a pressure regulator malfunction.

Attachment 14 to the EPU LAR provided an overview of the safety system setpoint control program pertaining to EPU and the associated methodology. Attachment 14 identified the MSL pressure - low function as one of the EPU setpoints pertaining to this discussion. The overview stated, in part, that:

> The instrument setpoint methodology currently implemented at PBAPS is based on the GEH Instrument Setpoint Methodology specified in NEDC-31336P-A, General Electric Instrument Setpoint Methodology (Proprietary). This methodology is procedurally-controlled and performed only by qualified personnel.
>
> Setpoint calculations begin by identifying the applicable Safety or Design Limit. The effects of transient overshoot, response times, and any modeling uncertainties are taken into account to obtain the Analytical Limit. Exelon calculates setpoints from the Analytical Limit, establishing margins between the Analytical Limit and the Allowable Value based on performance specifications for instruments being used. Independent instrument uncertainties are quantified, and then combined using the square-root-of-the-sum-of-the-squares method. Other non-device uncertainties are added algebraically.
>
> There is additional margin based on loop drift that is applied between the Allowable Value and the Nominal Trip Setpoint. Additional margin may be assigned between the Nominal Trip Setpoint and the Actual Trip Setpoint that takes into account the instrument As-Found Tolerance (AFT) and Leave Alone Zone, and any unique requirements for that device. If no additional margin is required, then the Actual Trip Setpoint is equal to the Nominal Trip Setpoint. The LAZ or as-left tolerance and the AFT are always around the ATSP.
>
> At the start of each calibration, instruments controlled by Technical Specifications are declared inoperable and removed from service. Upon completion, the Operations Shift Supervisor or Manager reviews the results of the surveillance and determines whether the results are acceptable based on Technical Specification operability requirements prior to returning the instrument to service.
>
> During calibration checks, if the as-found setpoint is outside the Leave Alone Zone, the condition is documented for trending purposes and appropriate

corrective actions are taken before the instrument is returned to service. Once actions have been taken to correct the condition, the instrument setpoint is reset to as close to the Actual Trip Setpoint value as practicable (i.e. within the Leave Alone Zone) and the instrument is returned to service. For cases in which the as-found setpoint value is within its Leave Alone Zone, the instrument is adjusted if desirable to as close to the Actual Trip Setpoint value as practicable.

The requirements in 10 CFR 50.36(c)(3), "Surveillance requirements," state that SRs are requirements relating to test, calibration or inspection to ensure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits and that the LCOs will be met. The AV for the MSL pressure - low function is used as the acceptance criteria in the applicable SRs, as listed in Table 3.3.6.1-1, in order to demonstrate operability of the function as required by LCO 3.3.6.1.

Based on the methodology, as discussed above, the NRC staff concludes that the proposed AV for the MSL pressure - low function has been determined in a manner that provides acceptance criteria sufficient to demonstrate whether the function is operable in accordance with LCO 3.3.6.1. As such, this provides reasonable assurance that the MSL pressure - low function will perform its intended function following successful completion of the associated SRs. Based on these considerations, the NRC staff concludes that the proposed change to the AV is acceptable.

Main Steam Line Flow - High

TS Table 3.3.6.1-1, Function 1.c, "Main Steam Line Flow - High," currently specifies an AV of "≤ 123.3 psid." The proposed amendment would change the AV to read "≤ 173.8 psid."

As discussed in the Bases for TS 3.3.6.1, the MSL flow - high function is provided to detect a break of the MSL and to initiate closure of the MSIVs. If the steam was allowed to continue flowing out of the break, the RPV would depressurize and the core could uncover. If the RPV water level decreases too far, fuel damage could occur. Therefore, the isolation is initiated on high flow to prevent or minimize core damage. This function is directly assumed in the analysis of a MSL break (MSLB). The isolation action, along with the scram function of the reactor protection system, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46 and offsite doses do not exceed the 10 CFR 50.67 limits.

As discussed in PUSAR Section 2.4.1.3.1, the effect on the MSL flow - high function due to EPU is increased reactor power level and steam flow. Based on these effects, as shown in PUSAR Table 2.4-1, the licensee plans to change the analytical limit (AL) for this function from 137.77 % of rated steam flow to 140 % of rated steam flow. A new trip setpoint and AV was calculated based on the change to the AL.

Attachment 14 to the EPU LAR provided an overview of the safety system setpoint control program pertaining to EPU and the associated methodology. Attachment 14 identified the MSL flow - high function as one of the EPU setpoints pertaining to this discussion. A discussion of the methodology is discussed in the MSL pressure - low function section above. In addition, specific details regarding the change to the AV were provided by the licensee in Attachment 5 to Supplement 3 to the EPU LAR dated May 24, 2013 (Reference 4). Attachment 5 is a proprietary document; a non-proprietary version was provided in Attachment 10 to Supplement 3 to the EPU LAR.

The AV for the MSL flow - high function is used as the acceptance criteria in the applicable SRs, as listed in Table 3.3.6.1-1, in order to demonstrate operability of the function as required by LCO 3.3.6.1.

Based on the methodology, as discussed above, the NRC staff concludes that the proposed AV for the MSL flow - high function has been determined in a manner that provides acceptance criteria sufficient to demonstrate whether the function is operable in accordance with LCO 3.3.6.1. As such, this provides reasonable assurance that the MSL flow - high function will perform its intended function following successful completion of the associated SRs. Based on these considerations the NRC staff concludes that the proposed change to the AV is acceptable.

3.13 TS 3.4.2 - Jet Pumps

SR 3.4.2.1 includes a note that states that the SR is not required to be performed "until 24 hours after > 25% RTP." The proposed amendment would change the "25% RTP" value to "23% RTP."

As discussed in Section 3.1.13 of Attachment 1 to the EPU LAR, these proposed changes are based on the fuel thermal limit monitoring threshold discussed in Section 2.8.2.1.2 of the PUSAR.

Based on the discussion in SE Section 3.3, the NRC staff concludes that the proposed changes to TS 3.4.2 are acceptable.

3.14 TS 3.4.3 - Safety Relief Valves and Safety Valves

LCO 3.4.3[4], "Safety Relief Valves (SRVs) and Safety Valves (SVs)," currently requires that: "The safety function of 12 valves (any combination of SRVs and SVs) shall be OPERABLE." The proposed amendment will require that 13 valves be operable instead of 12 valves.

SR 3.4.3.1 provides requirements for testing of the SRVs and SVs. It currently states that there are 2 SVs. The proposed amendment would change the number of SVs from 2 to 3.

The proposed changes to TS 3.4.3 are discussed in Section 3.1.14 of Attachment 1 to the EPU LAR and in Enclosure 9a to Attachment 9 of the EPU LAR. The specific changes were

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4 The marked-up TS pages shown in Attachment 2 to the EPU LAR (Reference 1), request to change the number of operable SRVs and SVs in LCO 3.4.3 from "11 valves" to "13 valves." However, on May 5, 2014, the NRC staff issued Amendment Nos. 290 and 293 for PBAPS Units 2 and 3, respectively (Reference 115), that revised the TSs to: (1) increase the allowable as-found SRV and SV lift setpoint tolerance from ± 1% to ± 3%; (2) increase the required number of operable SRVs and SVs from 11 to 12; and (3) increase the SLC system pump discharge pressure from 1255 psig to 1275 psig. In Supplement 27 to the EPU LAR (Reference 116), Exelon submitted revised marked-up TS pages to reflect that the number of operable SRVs and SVs is being increased from 12 valves to 13 valves.

necessary to support the licensee's analysis of overpressure protection of the reactor coolant pressure boundary under EPU conditions.

As discussed above in SE Section 2.8.4.2, the NRC staff has reviewed the proposed changes to TS 3.4.3 as part of its review of the licensee's analysis related to overpressure protection. The staff concluded that the proposed EPU is acceptable with respect to overpressure protection, in part, taking into account the proposed changes to TS 3.4.3. Based on the review discussed in SE Section 2.8.4.2, the NRC staff concludes that the proposed changes to TS 3.4.3 are acceptable.

3.15 TS 3.5.1 - Emergency Core Cooling System - Operating

The proposed amendment would change the frequency of performing SR 3.5.1.5 from "Once each startup prior to exceeding 25% RTP" to "Once each startup prior to exceeding 23% RTP." As discussed in Section 3.1.15 of Attachment 1 to the EPU LAR, this change is based on the change in reactor power and is being made for consistency with TS 3.4.2. The NRC staff finds that the proposed change to SR 3.5.1.5 is acceptable since it provides consistency with the other SRs being changed as being applicable at 23% RTP rather than the current value of 25% RTP.

The proposed amendment would change the minimum required flow rate for the low pressure coolant injection (LPCI) pumps in SR 3.5.1.7 from 10,900 gpm to 8,600 gpm. As discussed in Enclosure 9c to Attachment 9 to the EPU LAR, for EPU, the ECCS pump NPSH analyses assume implementation of the RHR heat exchanger cross-tie modification and no credit for CAP. The licensee's analyses determined that, in the most limiting scenario, 8,600 gpm is the minimum LPCI mode flow necessary to ensure adequate core cooling. The NRC staff finds that the proposed change to SR 3.5.1.7 is acceptable since it is consistent with the EPU design analyses.

3.16 TS 3.5.2 - Emergency Core Cooling System - Shutdown

The proposed amendment would change the minimum required flow rate for the LPCI pumps in SR 3.5.2.5 from 10,900 gpm to 8,600 gpm. As discussed in Enclosure 9c to Attachment 9 to the EPU LAR, for EPU, the ECCS pump NPSH analyses assume implementation of the RHR heat exchanger cross-tie modification and no credit for CAP. The licensee's analyses determined that, in the most limiting scenario, 8,600 gpm is the minimum LPCI mode flow necessary to ensure adequate core cooling. The NRC staff finds that the proposed change to SR 3.5.2.5 is acceptable since it is consistent with the EPU design analyses.

3.17 TS 3.6.1.3 - Primary Containment Isolation Valves

SR 3.6.1.3.14 currently requires verification that the combined MSIV leakage rate for all 4 main steam lines is ≤ 204 standard cubic feet per hour (scfh) when tested at ≥ 25 psig. This SR also requires that the MSIV leakage rate is ≤ 116 scfh for any one steam line when tested at ≥ 25 psig. The proposed amendment would change the 204 scfh value to 170 scfh and the 116 scfh value to 85 scfh.

As discussed in Section 3.1.17 of Attachment 1 to the EPU LAR, the proposed changes to the MSIV leakage rates are needed due to increased activity in the core at EPU conditions. Specifically, the licensee stated that:

> MSIV leakage rate is an important input to the alternative source term (AST) LOCA dose analysis. Lowering the MSIV leakage rate increases the time allowed for contaminates to plate out in the main steam line, which results in a decrease in contaminates being released and lower dose rates. This affect, along with the lower allowable leakage rate, offsets the increase in source term from operations at EPU conditions.
>
> The proposed MSIV leakage rate changes are justified in order to maintain doses in the Exclusion Area Boundary (EAB), the Low Population Zone (LPZ) and the Control Room (CR) doses below 10 CFR 50.67 limits for EPU.

As discussed in Section 2.9.2, "Radiological Consequences Analyses Using Alternative Source Term," of the PUSAR, the current PBAPS AST analyses assumes a total MSIV leakage rate (i.e., all four main steam lines combined) of 360 scfh and 205 scfh for a single main steam line. These leakage values are based on the peak calculated containment internal pressure for a design-basis LOCA, P_a, of 49.1 psig as discussed in UFSAR Section 14.9.2 and as shown in UFSAR Table 14.9.10. Since SR 3.6.1.3.14 uses a test pressure of 25 psig, an extrapolation factor is used to convert the calculated leakage rates at 49.1 psig to the measured leakage rates at 25 psig. The extrapolation factor was calculated to be 1.764 as shown in Section 7.2.6 of PBAPS Calculation PM-1077, Revision 1, "Post-LOCA EAB, LPZ and CR Doses Using Alternative Source Term" (ADAMS Accession No. ML082260412). As such, the current SR 3.6.1.3.14 leakage values were determined as follows:

(360 scfh at 49.1 psig) ÷ 1.764 = 204 scfh at 25 psig

(205 scfh at 49.1 psig) ÷ 1.764 = 116 scfh at 25 psig

As discussed in PUSAR Section 2.9.2, under EPU conditions, the calculated leakage rate for all 4 main steam lines combined would change from 360 scfh to 300 scfh. The calculated leakage rate for a single main steam lime would change from 205 scfh to 150 scfh. Using the extrapolation factor discussed above would yield the following measured leakage rates at 25 psig:

(300 scfh at 49.1 psig) ÷ 1.764 = 170 scfh at 25 psig

(150 scfh at 49.1 psig) ÷ 1.764 = 85 scfh at 25 psig

Based on the above, the NRC staff finds that the proposed changes to SR 3.6.1.3.14 are acceptable since they are consistent with the AST analyses at EPU conditions.

3.18 TS 3.6.2.3 - Residual Heat Removal System Suppression Pool Cooling

The proposed amendment would change the minimum required flow rate, for each RHR pump operating in the suppression pool cooling mode, in SR 3.6.2.3.2, from 10,000 gpm to

8,600 gpm. As discussed in Section 3.1.18 of Attachment 1 to the EPU LAR, this change is based on eliminating reliance on CAP credit through implementation of the RHR heat exchanger cross-tie and high pressure service water cross-tie modifications. The licensee stated that the new minimum suppression pool cooling flow rate of 8,600 gpm is an assumption in the containment safety analyses and is sufficient, when combined with credit for a reduced heat exchanger fouling limit, to maintain peak suppression pool temperatures below design limits.

The NRC staff finds that the proposed change to SR 3.6.2.3.2 is acceptable since it is consistent with the EPU design analyses for suppression pool cooling.

The proposed amendment would add new SR 3.6.2.3.3, which would read as follows:

> Verify manual transfer capability of power supply for the RHR motor-operated flow control valve and the RHR cross-tie motor-operated valve from the normal source to the alternate source.

The capability to transfer from the normal to the alternate supply would be tested on a frequency established in accordance with the Surveillance Frequency Control Program.

As discussed in Attachment 1 of Supplement 5 to the EPU LAR (Reference 6), following submittal of the application, the licensee identified the need to provide the control room operator the capability to transfer the power supply of the RHR motor-operated flow control valve and the RHR cross-tie motor-operated from a safety-related normal source to a safety-related alternate source in the event of a loss of offsite power and the failure of an emergency alternating current (AC) electrical source.

The NRC finds that the proposed new SR 3.6.2.3.3 provides requirements that help to assure that a single failure of an emergency AC electrical source will not result in failure of these valves. This, in turn, helps to assure operability of the associated RHR suppression pool cooling system, as required by LCO 3.6.2.3. As such, the proposed new SR is consistent with the requirements in 10 CFR 50.36(c)(3), which requires, in part, that SRs be established to provide assurance that LCOs will be met. Based on these considerations, the NRC staff finds that the proposed new SR is acceptable.

3.19 TS 3.6.2.4 - Residual Heat Removal System Suppression Pool Spray

The proposed amendment would add new SR 3.6.2.4.3, which would read as follows:

> Verify manual transfer capability of power supply for the RHR motor-operated flow control valve and the RHR cross-tie motor-operated valve from the normal source to the alternate source.

The capability to transfer from the normal to the alternate supply would be tested on a frequency established in accordance with the Surveillance Frequency Control Program.

Similar to the discussion above in SE Section 3.18, the NRC finds that the proposed new SR 3.6.2.4.3 provides requirements that help to assure that a single failure of an emergency AC electrical source will not result in failure of these valves. This, in turn, helps to assure operability of the associated RHR suppression pool spray system as required by LCO 3.6.2.4. As such, the proposed new SR is consistent with the requirements in 10 CFR 50.36(c)(3), which requires, in part, that SRs be established to provide assurance that LCOs will be met. Based on these considerations, the NRC staff finds that the proposed new SR is acceptable.

3.20 TS 3.6.2.5 - Residual Heat Removal System Drywell Spray

As discussed in Supplement 27 to the EPU LAR (Reference 116), the proposed amendment would add new SR 3.6.2.5.3, which would read as follows:

> Verify manual transfer capability of power supply for the RHR motor-operated flow control valve and the RHR cross-tie motor-operated valve from the normal source to the alternate source.

The capability to transfer from the normal to the alternate supply would be tested on a frequency established in accordance with the Surveillance Frequency Control Program.

Similar to the discussion above in SE Sections 3.18 and 3.19, the NRC finds that the proposed new SR 3.6.2.5.3 provides requirements that help to assure that a single failure of an emergency AC electrical source will not result in failure of these valves. This, in turn, helps to assure operability of the associated RHR drywell spray system as required by LCO 3.6.2.5. As such, the proposed new SR is consistent with the requirements in 10 CFR 50.36(c)(3), which requires, in part, that SRs be established to provide assurance that LCOs will be met. Based on these considerations, the NRC staff finds that the proposed new SR is acceptable.

3.21 TS 3.7.1 - High Pressure Service Water (HPSW) System

As discussed in Section 3.1.19 of Attachment 1 to the EPU LAR, the proposed amendment would make a number of changes to TS 3.7.1, "High Pressure Service Water (HPSW) System," based on improving NPSH margin and eliminating reliance on CAP credit through implementation of the RHR heat exchanger cross-tie and HPSW cross-tie modifications. The proposed changes are discussed below.

LCO 3.7.1

LCO 3.7.1 currently reads as follows:

> Two HPSW subsystems shall be OPERABLE.

The proposed amendment would revise the LCO to read:

> Two HPSW subsystems and the HPSW cross tie shall be OPERABLE.

The HPSW cross-tie modification is discussed in Enclosure 9d to Attachment 9 of the EPU LAR. As discussed in this enclosure, the HPSW system is designed to provide cooling water for the RHR system heat exchangers under post-accident conditions. The HPSW system consists of two independent and redundant loops. Each loop contains two HPSW pumps installed in parallel. The TSs require two HPSW subsystems to be operable; each subsystem consists of one HPSW loop with one operable HPSW pump.

As discussed in Enclosure 9d to Attachment 9 of the EPU LAR, the RHR cross-tie modification will enable a second RHR heat exchanger to be cross-tied to the operating RHR pump. Use of two RHR heat exchangers increases the cooling capacity of the system, which will improve NPSH margin. This increase in NPSH margin eliminates the need to take credit for CAP for DBAs and transients in which only one RHR pump is available and the suppression pool temperature is elevated. In these cases, a second HPSW pump must be started to provide cooling water to the tube side of the second RHR heat exchanger. As a result of emergency diesel generator loading limitations, two HPSW pumps within a single division may not always be available. The HPSW system cross-tie modification will enable the control room operator to manually align HPSW pumps from the opposite division in order to provide cooling water to the two operating RHR heat exchangers.

Since the licensee's analyses supporting the proposed EPU assume the use of two HPSW pumps to provide the required cooling capacity, and the HPSW cross-tie is needed to provide this capability (while assuming a single failure), the addition of the HPSW cross-tie to LCO 3.7.1 is needed to meet the requirements of 10 CFR 50.36. Specifically, Criterion 3 in 10 CFR 50.36(c)(2)(ii) requires that an LCO be established for a "structure, system, or component that is part of the primary success path and which functions or actuates to mitigate a design basis accident or transient that either assumes the failure of or presents a challenge to the integrity of a fission product barrier." Since the proposed change is consistent with 10 CFR 50.36, the NRC staff finds that the changes to LCO 3.7.1 are acceptable.

TS 3.7.1 New Condition B

New TS 3.7.1 Condition B would be added, which would read as follows:

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. HPSW cross tie inoperable.	B.1 Restore HPSW cross tie to OPERABLE status.	7 days

As discussed in Section 3.1.19 of Attachment 1 to the EPU LAR, under Condition B, two HPSW subsystems would be operable and the two operable pumps and flow paths would ensure two HPSW pumps are available to provide adequate heat removal capacity following a DBA. However, the reliability is reduced since a single failure in the HPSW system could result in loss of the HPSW function.

The NRC staff finds that the proposed new Condition B is acceptable since: (1) the HPSW system will still be able to provide the required cooling capability (assuming no single failure occurs); and (2) there is a low probability of a DBA occurring during the 7 day completion time period for restoring the HPSW cross-tie to operable status.

TS 3.7.1 Existing Conditions B, C, and D

Existing TS 3.7.1 Conditions B, C and D would be relabeled as Conditions C, D, and E, respectively, due the addition of new Condition B (discussed above). The NRC staff finds that these changes are administrative in nature and, therefore, are acceptable.

In addition to the administrative changes discussed above, existing Condition B (relabeled as Condition C) would be modified. This Condition currently reads as follows:

> Required Action and associated Completion Time of Condition A not met.

The proposed amendment would change the Condition to read as follows:

> Required Action and associated Completion Time of Condition A or B not met.

This Condition would require that the plant be in Mode 3 (hot shutdown) within 12 hours if the inoperable HPSW subsystem (Condition A) or the inoperable HPSW cross-tie (Condition B) are not restored to operable status within the required completion time of 7 days. The NRC staff finds the proposed change to the relabeled Condition C is acceptable since it provides consistent requirements for the HPSW cross-tie as those currently in place for the HPSW subsystem.

New SR 3.7.1.2

The proposed amendment would add new SR 3.7.1.2, which would read as follows:

> Verify manual transfer capability of power supply for the HPSW cross-tie motor-operated valve and the RHR heat exchanger HPSW outlet valve from the normal source to the alternate source.

The capability to transfer from the normal to the alternate supply would be tested on a frequency established in accordance with the Surveillance Frequency Control Program.

Similar to the discussion above in SE Section 3.18, the NRC finds that the proposed new SR 3.7.1.2 provides requirements that help to assure that a single failure of an emergency AC electrical source will not result in failure of these valves. This, in turn, helps to assure operability of the associated HPSW system, as required by LCO 3.7.1. As such, the proposed new SR is consistent with the requirements in 10 CFR 50.36(c)(3), which requires, in part, that SRs be established to provide assurance that LCOs will be met. Based on these considerations, the NRC staff finds that the proposed new SR is acceptable.

3.22 TS 3.7.6 - Main Turbine Bypass System

The TS 3.7.6 LCO Applicability and LCO Required Action B.1 currently include requirements associated with a thermal power limit of 25%. The proposed amendment would change "25% RTP" value to "23% RTP" in both instances.

As discussed in Section 3.1.20 of Attachment 1 to the EPU LAR, these proposed changes are based on the fuel thermal limit monitoring threshold discussed in Section 2.8.2.1.2 of the PUSAR.

Based on the discussion in SE Section 3.3, the NRC staff concludes that the proposed changes to TS 3.7.6 are acceptable.

3.23 TS 3.8.3 - Diesel Fuel Oil, Lube Oil, and Starting Air

Condition A in TS 3.8.3 currently requires that the stored diesel fuel oil be maintained in a range of greater than 27,500 gallons and less than 31,000 gallons. The proposed amendment would modify Condition A to require that the stored diesel fuel oil be maintained in a range of greater than 29,000 gallons and less than 33,000 gallons.

SR 3.8.3.1 currently requires that the fuel oil storage tank be verified to contain at least 31,000 gallons. The proposed amendment would change the 31,000 gallon value to 33,000 gallons. As shown in UFSAR Table 8.5.3, the storage tank capacity is 39,655 gallons.

As discussed in Section 3.1.21 of Attachment 1 to the EPU LAR, the lower volume, in Condition A, relates to a 6-day supply of fuel oil and the higher volume relates to a 7-day supply. The proposed change in the required volumes is based on an increase in the total EDG loading under EPU conditions for a DBA-LOCA with a loss of offsite power (LOOP) event.

The NRC staff finds that the proposed changes to TS 3.8.3 are acceptable, since they provide values consistent with the EPU design analyses.

3.24 TS Bases

Attachment 3 to the EPU LAR and Attachment 3 to Supplement 5 to the EPU LAR provided revised TS Bases pages to be implemented with the associated TS changes. These pages were provided for information only and will be revised by the licensee in accordance with the TS Bases Control Program discussed in TS 5.5.10.

3.25 Unit 2 License Condition - Potential Adverse Flow Effects

The following would be added to the PBABS, Unit 2, FOL as license condition 2.C(15) as shown in Supplement 26 to the EPU LAR (Reference 114), as modified by Supplement 28 to the EPU LAR (Reference 117). This license condition is addressed in SE Section 2.2.6.

> (15) Potential Adverse Flow Effects
>
> In conjunction with the license amendment to revise paragraph 2.C(1) of Renewed Facility Operating License No. DPR-44, for Peach Bottom Unit 2, to reflect the new maximum licensed reactor core power level of 3951 megawatts thermal (MWt), the license is also amended to add the following license condition. 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). This license condition is applicable to the initial power ascension from 3514 MWt to the extended power uprate (EPU) power level of 3951 MWt:

(a) The following requirements are placed on the initial operation of the facility, above the thermal power level of 3514 MWt, for the power ascension to 3951 MWt. These conditions are applicable until the first time full EPU conditions (3951 MWt) are achieved. If the number of active main steam line (MSL) strain gauges is less than two strain gauges (180 degrees apart) at any of the eight MSL locations, Exelon Generation Company will stop power ascension and repair/replace the damaged strain gauges and only then resume power ascension. In addition, sufficient on-dryer strain gauges must remain in working order to monitor all dryer peak stress locations with a minimum alternating stress ratio (MASR) less than 1.5. In the event there are no working on-dryer strain gauges, with coherence of greater than 0.5 with any peak stress location, Exelon Generation Company will: (1) stop power ascension; (2) evaluate the dryer MASR at the current power level and at the projected EPU power level; and (3) provide the results to the NRC Project Manager via e-mail. Exelon Generation Company shall not resume power ascension for at least 24 hours after the NRC Project Manager confirms receipt of the MASR results unless, prior to the expiration of the 24 hour period, the NRC Project Manager advises that the NRC staff has no objections to the continuation of power ascension. Furthermore, power ascension may only resume if Exelon Generation Company determines that the dryer MASR will remain greater than 1.0.

1. Exelon Generation Company shall provide a brief stress summary report for the replacement steam dryer (RSD) based on MSL strain gauge and on-dryer instrument data collected at or near 3514 MWt for NRC review before increasing power above 3514 MWt. Exelon Generation Company shall also provide a brief vibration summary report for piping and valve vibration data collected at or near 3514 MWt for NRC review before increasing power above 3514 MWt. Both summary reports shall be provided by e-mail to the NRC Project Manager. Exelon Generation Company shall not increase power above 3514 MWt for at least 240 hours after the NRC Project Manager confirms receipt of the reports unless, prior to expiration of the 240 hour period, the NRC Project Manager advises that the NRC staff has no objections to the continuation of power ascension. The stress summary report shall include the information in items a through f, and the vibration summary report shall include the information in items g through i, as follows:

a. A comparison of predicted and measured pressure spectra plots on the RSD.

b. A comparison of predicted and measured root mean square (RMS) strains and spectra plots on the RSD.

c. End-to-end bias errors and uncertainties (B/Us) for RSD strains, along with a demonstration that the application of these B/Us leads to RSD strain simulations that bound the measured spectra at dominant frequencies and RMS strains at all active strain gauge locations.

d. RSD strain gauge limits based on benchmarking performed near 3514 MWt. This will include the predicted RSD strains at each measured location and the corresponding updated MASR near 3514 MWt.

e. Predicted (extrapolated) strains at the active RSD strain gauge locations at 104% of 3514 MWt and an evaluation against acceptance limits.

f. Predicted RSD stresses and MASRs at EPU.

g. Vibration data for piping and valve locations deemed prone to vibration and vibration monitoring locations identified in Attachment 13 to the EPU application dated September 28, 2012, and Supplement 16 dated December 20, 2013, including the following locations: MSLs (including those in the drywell, turbine building and in the steam tunnel), Feedwater Lines (including those in the drywell and turbine building), Safety Relief Valves (SRVs) and Main Steam Isolation Valves in the drywell.

h. An evaluation of the measured vibration data collected in item 1.g above compared against acceptance limits.

i. Predicted vibration values and associated acceptance limits at approximately 104 percent, 108 percent, and 112.4 percent of 3514 MWt using the data collected in item 1.g above.

2. Exelon Generation Company shall monitor the RSD strain gauges during power ascension above 3514 MWt for increasing strain fluctuations. Upon the initial increase of power above 3514 MWt until reaching 3951 MWt, Exelon Generation Company shall collect data from the RSD strain gauges at nominal 2 percent thermal power increments and

evaluate steam dryer stress ratios based on these data. Summaries of the results shall be provided via e-mail to the NRC Project Manager at approximately 104 percent and 108 percent of 3514 MWt.

3. Exelon Generation Company shall monitor the MSL strain gauges during power ascension above 3514 MWt for increasing pressure fluctuations in the main steam lines. Upon the initial increase of power above 3514 MWt until reaching 3951 MWt, Exelon Generation Company shall collect data from the MSL strain gauges and on-dryer instruments at nominal 2 percent thermal power increments.

4. Exelon Generation Company shall hold the facility at approximately 104 percent and 108 percent of 3514 MWt to perform the following:

    a. Collect strain data from the MSL strain gauges and collect data from on-dryer instruments (accelerometers, strain gauges, and pressure transducers).

    b. Collect vibration data for the locations included in the vibration summary report discussed above.

    c. Evaluate steam dryer performance based on RSD strain gauge data.

    d. Evaluate the measured vibration data (collected in item 4.b above) at that power level, data projected to EPU conditions, trends, and comparison with the acceptance limits.

    e. Provide the steam dryer evaluation and the vibration evaluation, including the data collected, via e-mail to the NRC Project Manager, upon completion of the evaluation for each of the two hold points.

    f. Exelon Generation Company shall submit a comparison of predicted and measured pressures and strains (RMS and spectra) on the RSD at 104% of 3514 MWt and 108% of 3514 MWt during power ascension.

    g. Exelon Generation Company shall not increase power above each hold point until 96 hours after the NRC Project Manager confirms receipt of the evaluations unless, prior to the expiration of the 96 hour period, the NRC Project Manager advises that the NRC staff has no objections to the continuation of power ascension.

5. If any RMS level measured by the active RSD strain gauges exceeds allowable Level 1 limits, Exelon Generation Company shall return the facility to a power level at which the limit(s) is not exceeded. Exelon Generation Company shall resolve the discrepancy, evaluate and document the continued structural integrity of the steam dryer, and provide that documentation to the NRC Project Manager via e-mail prior to further increases in reactor power. If a revised stress analysis is performed and new RSD strain limits are developed, then Exelon Generation Company shall not further increase power above each hold point until 96 hours after the NRC Project Manager confirms receipt of the documentation or until the NRC Project Manager advises that the NRC staff has no objections to the continuation of power ascension, whichever comes first. Additional detail is provided in paragraph (b)1 below.

(b) Exelon Generation Company shall implement the following actions for the initial power ascension from 3514 MWt to 3951 MWt condition:

1. In the event that RMS strain levels for active RSD strain gauges are identified to exceed the allowable Level 1 limits during power ascension above 3514 MWt, Exelon Generation Company shall re-evaluate dryer loads and stresses, and re-establish updated MASRs and RSD strain gauge RMS limits. In the event that stress analyses are re-performed based on new strain gauge data to address paragraph (a)5 above, the revised load definition, stress analysis, and limits shall include:

    a. Determination of end-to-end B/Us and their application in determining maximum alternating stress intensities.

    b. Use of bump-up factors associated with all of the SRV acoustic resonances, as determined from the scale model test results or in-plant data acquired during power ascension.

2. After reaching 3951 MWt, Exelon Generation Company shall obtain measurements from the MSL strain gauges and establish the steam dryer flow-induced vibration load fatigue margin for the facility, update the dryer stress report, and re-establish the RSD strain gauge limits based on the updated load definition. These data will be provided to the NRC staff as described below in paragraph (e).

(c) Exelon Generation Company shall prepare the EPU power ascension test procedure to include:

1. The stress limits and the corresponding RSD strain limits to be applied for evaluating steam dryer performance.

2. Specific hold points and their durations during EPU power ascension.

3. Activities to be accomplished during the hold points.

4. Plant parameters to be monitored.

5. Inspections and walkdowns to be conducted for steam, feedwater, and condensate systems and components during the hold points.

6. Methods to be used to trend plant parameters.

7. Acceptance criteria for monitoring and trending plant parameters, and conducting the walkdowns and inspections.

8. Actions to be taken if acceptance criteria are not satisfied.

9. Verification of the completion of commitments and planned actions specified in the 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 3514 MWt. Exelon Generation Company shall provide the related EPU startup test procedure sections to the NRC Project Manager via e-mail prior to increasing power above 3514 MWt.

(d) 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:

1. During initial power ascension testing above 3514 MWt, each of the two hold points shall be at increments of 4 percent of 3514 MWt.

2. Level 1 performance criteria.

3. The methodology for establishing the RSD strain limits used for the Level 1 and Level 2 performance.

(e) 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 in accordance with 10 CFR 50.4. The report shall include a final load definition and stress report of the steam dryer, including the results of a complete re-analysis using the end-to-end B/Us determined at EPU conditions and a comparison of predicted and measured pressures and strains (RMS levels and spectra) on the RSD. The report shall be submitted within 90 days of the completion of EPU power ascension testing for Peach Bottom Unit 2.

(f) During the first two scheduled refueling outages after reaching EPU conditions, a visual inspection shall be conducted of the steam dryer as described in the inspection guidelines contained in WCAP-17635-P.

(g) The results of the visual inspections of the steam dryer shall be submitted to the NRC staff in a report in accordance with 10 CFR 50.4. The report shall be submitted within 90 days following startup from each of the first two respective refueling outages.

(h) Within 6 months following completion of the second refueling outage, after the implementation of the EPU, the licensee shall submit a long-term steam dryer inspection plan based on industry operating experience along with the baseline inspection results.

The license condition described above shall expire: (1) upon satisfaction of the requirements in paragraphs (f) and (g), provided that a visual inspection of the steam dryer does not reveal any new unacceptable flaw(s) or unacceptable flaw growth that is due to fatigue, and; (2) upon satisfaction of the requirements specified in paragraph (h).

3.26 Unit 3 License Condition - Potential Adverse Flow Effects

The following would be added to the PBABS, Unit 3, FOL as license condition 2.C(15) as shown in Supplement 26 to the EPU LAR (Reference 114), as modified by Supplement 28 to the EPU LAR (Reference 117). This license condition is addressed in SE Section 2.2.6.

(15) Potential Adverse Flow Effects

In conjunction with the license amendment to revise paragraph 2.C(1) of Renewed Facility Operating License No. DPR-56, for Peach Bottom Unit 3, to reflect the new maximum licensed reactor core power level of 3951 megawatts thermal (MWt), the license is also amended to add the following license condition. 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). This license condition is applicable to the initial power ascension from 3514 MWt to the extended power uprate (EPU) power level of 3951 MWt:

(a) The following requirements are placed on the initial operation of the facility, above the thermal power level of 3514 MWt, for the power ascension to 3951 MWt. These conditions are applicable until the first time full EPU conditions (3951 MWt) are achieved. If the number of active main steam line (MSL) strain gauges is less than two strain gauges (180 degrees apart) at any of the eight MSL locations, Exelon Generation Company will stop power ascension and repair/replace the damaged strain gauges and only then resume power ascension.

1. At least 90 days prior to the start of the Peach Bottom Unit 3 EPU outage, Exelon Generation Company shall revise the Peach Bottom Unit 3 replacement steam dryer (RSD) analysis utilizing the Unit 2 on-dryer strain gauge based end-to-end Bias errors and Uncertainties (B/Us) at EPU conditions, and submit the information including the updated limit curves and a list of dominant frequencies for Unit 3, to the NRC as a report in accordance with 10 CFR 50.4.

2. Exelon Generation Company shall evaluate the Unit 3 limit curves prepared in (a)1 above based on new MSL strain gauge data collected following the Unit 3 EPU outage at or near 3514 MWt. If the limit curves change, the new post-EPU outage limit curves shall be provided by e-mail to the NRC Project Manager. Exelon Generation Company shall not increase power above 3514 MWt for at least 96 hours after the NRC Project Manager confirms receipt of the reports unless, prior to expiration of the 96 hour period, the NRC Project Manager advises that the NRC staff has no objections to the continuation of power ascension.

3. Exelon Generation Company shall provide a brief vibration summary report, for piping and valves vibration data collected at or near 3514 MWt, for NRC review before increasing power above 3514 MWt. The summary report shall be provided by e-mail to the NRC Project Manager. Exelon Generation Company shall not increase power above 3514 MWt for at least 96 hours after the NRC Project Manager confirms receipt of the report unless, prior to expiration of the 96 hour period, the NRC Project Manager advises that the NRC staff has no objections to the continuation of power ascension. The vibration summary report shall include the information in items a through c, as follows:

    a. Vibration data for piping and valve locations deemed prone to vibration and vibration monitoring locations identified in Attachment 13 to the EPU application dated

September 28, 2012, and Supplement 16 dated December 20, 2013, including the following locations: MSLs (including those in the drywell, turbine building and in the steam tunnel), Feedwater Lines (including those in the drywell and turbine building), Safety Relief Valves (SRVs) and the Main Steam Isolation Valves in the drywell.

b. An evaluation of the measured vibration data collected in item 3.a above compared against acceptance limits.

c. Predicted vibration values and associated acceptance limits at approximately 104 percent, 108 percent, and 112.4 percent of 3514 MWt using the data collected in item 3.a, above.

4. Exelon Generation Company shall monitor the MSL strain gauges during power ascension above 3514 MWt for increasing pressure fluctuations in the steam lines. Upon the initial increase of power above 3514 MWt until reaching 3951 MWt, Exelon Generation Company shall collect data from the MSL strain gauges at nominal 2 percent thermal power increments and evaluate steam dryer performance based on this data.

5. During power ascension at each nominal 2 percent power level above 3514 MWt, Exelon Generation Company shall compare the MSL data to the approved limit curves based on end-to-end B/Us from the Peach Bottom Unit 2 benchmarking at EPU conditions and determine the minimum alternating stress ratio (MASR). A summary of the results shall be provided for NRC review at approximately 104 percent and 108 percent of 3514 MWt. The summary report shall be provided to the NRC Project Manager via e-mail.

6. Exelon Generation Company shall hold the facility at approximately 104 percent and 108 percent of 3514 MWt to perform the following:

   a. Collect strain data from the MSL strain gauges.

   b. Collect vibration data for the locations included in the vibration summary report discussed above.

   c. Evaluate steam dryer performance based on MSL strain gauge data.

   d. Evaluate the measured vibration data (collected in item 6.b above) at that power level, data projected to EPU conditions, trends, and comparison with the acceptance limits.

e. Provide the steam dryer evaluation and the vibration evaluation, including the data collected, via e-mail to the NRC Project Manager, upon completion of the evaluation for each of the hold points.

f. Exelon Generation Company shall not increase power above each hold point until 96 hours after the NRC Project Manager confirms receipt of the evaluations unless, prior to the expiration of the 96 hour period, the NRC Project Manager advises that the NRC staff has no objections to the continuation of power ascension.

7. If any frequency peak from the MSL strain gauge data exceeds the Level 1 limit curves, Exelon Generation Company shall return the facility to a power level at which the limit curve is not exceeded. Exelon Generation Company shall resolve the discrepancy, evaluate and document the continued structural integrity of the steam dryer, and provide that documentation to the NRC Project Manager via e-mail prior to further increases in reactor power. If a revised stress analysis is performed and new limit curves are developed, then Exelon Generation Company shall not further increase power above each hold point until 96 hours after the NRC Project Manager confirms receipt of the documentation or until the NRC Project Manager advises that the NRC staff has no objections to the continuation of power ascension, whichever comes first. Additional detail is provided in paragraph (b)1 below.

(b) Exelon Generation Company shall implement the following actions for the initial power ascension from 3514 MWt to 3951 MWt condition:

1. In the event that acoustic signals (in MSL strain gauge signals) are identified that exceed the Level 1 limit curves during power ascension above 3514 MWt, Exelon Generation Company shall re-evaluate dryer loads and stresses, and re-establish the limit curves. In the event that stress analyses are re-performed based on new strain gauge data to address paragraph (a)7 above, the revised load definition, stress analysis, and limit curves shall include:

a. Application of end-to-end B/Us as determined from Peach Bottom Unit 2 EPU measurements.

b. Use of bump-up factors associated with all of the SRV acoustic resonances as determined from the scale model test results or in-plant data acquired during power ascension.

2. After reaching 3951 MWt, Exelon Generation Company shall obtain measurements from the MSL strain gauges 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 load definition. These data will be provided to the NRC staff as described below in paragraph (e).

(c) Exelon Generation Company shall prepare the EPU power ascension test procedure to include:

1. The MSL strain gage limit curves to be applied for evaluating steam dryer performance, based on end-to-end B/Us from Peach Bottom Unit 2 benchmarking at EPU conditions

2. Specific hold points and their durations during EPU power ascension.

3. Activities to be accomplished during the hold points.

4. Plant parameters to be monitored.

5. Inspections and walkdowns to be conducted for steam, feedwater, and condensate systems and components during the hold points.

6. Methods to be used to trend plant parameters.

7. Acceptance criteria for monitoring and trending plant parameters, and conducting the walkdowns and inspections.

8. Actions to be taken if acceptance criteria are not satisfied.

9. Verification of the completion of commitments and planned actions specified in the 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 3514 MWt. Exelon Generation Company shall provide the related EPU startup test procedure sections to the NRC Project Manager via e-mail prior to increasing power above 3514 MWt.

(d) 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:

1. During initial power ascension testing above 3514 MWt, each of the two hold points shall be at increments of approximately 4 percent of 3514 MWt.

2. Level 1 performance criteria.

3. The methodology for establishing the limit curves used for the Level 1 and Level 2 performance.

(e) 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 in accordance with 10 CFR 50.4. The report shall include a final load definition and stress report of the steam dryer, including the results of a complete re-analysis using the end-to-end B/Us from Peach Bottom Unit 2 benchmarking at EPU conditions. The report shall be submitted within 90 days of the completion of EPU power ascension testing for Peach Bottom Unit 3.

(f) During the first two scheduled refueling outages after reaching EPU conditions, a visual inspection shall be conducted of the steam dryer as described in the inspection guidelines contained in WCAP-17635-P.

(g) The results of the visual inspections of the steam dryer shall be submitted to the NRC staff in a report in accordance with 10 CFR 50.4. The report shall be submitted within 90 days following startup from each of the first two respective refueling outages.

(h) Within 6 months following completion of the second refueling outage, after the implementation of the EPU, the licensee shall submit a long-term steam dryer inspection plan based on industry operating experience along with the baseline inspection results.

The license condition described above shall expire: (1) upon satisfaction of the requirements in paragraphs (f) and (g), provided that a visual inspection of the steam dryer does not reveal any new unacceptable flaw(s) or unacceptable flaw growth that is due to fatigue, and; (2) upon satisfaction of the requirements specified in paragraph (h).

4.0 REGULATORY COMMITMENTS

The licensee made a number of the commitments as shown in Attachment 7 to the EPU LAR. In Supplement 20 to the EPU LAR (Reference 75), the licensee withdrew Attachment 7 to the EPU LAR. The licensee stated in Supplement 20 that, based on its review of the EPU LAR submittal and the licensee's current regulatory commitment policy, it has been determined that each of the items listed in Attachment 7 no longer meet the definition of a formal commitment. As such, there are no regulatory commitments associated with the EPU LAR.

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.

- EPU startup testing as described in Attachment 10 to the EPU LAR (Tables 10-1 and 10-2).

- Plant modifications associated with elimination of containment accident pressure credit. These modifications include: (1) residual heat removal system heat exchanger cross-tie modification; (2) high pressure service water system cross-tie modification; and (3) condensate storage tank modifications. These modifications are discussed in Attachment 9 to the EPU LAR (Enclosures 9c, 9d, and 9e).

- Standby liquid control system modifications as described in Enclosure 9b to Attachment 9 to the EPU LAR.

- As discussed in Section 2.2.4.2 of Attachment 4 to the EPU LAR, there were a number of motor-operated valves which either had a negative or low margin impact with respect to change in differential pressure based on the EPU analyses. These valves will require modification to return them to acceptable margin. The specific valves are identified in Table 2.2-14 of Attachment 4 to the EPU LAR.

In addition to the recommended areas for inspection listed above, NRC Inspection Procedure 71004, "Power Uprate," dated April 30, 2010 (ADAMS Accession No. ML100200040), provides guidance for conducting inspections associated with power uprate amendments including considerations for selecting samples.

6.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Pennsylvania State official was notified of the proposed issuance of the amendments. The State official, Mr. Brad Fuller, from the Pennsylvania (PA) Department of Environmental Protection (DEP), provided the following comments via e-mail on July 20, 2014:

> The PA DEP's Bureau of Radiation Protection (BRP) has reviewed Exelon's proposed extended power uprate (EPU) amendment for an increase of approximately 12.4 percent. The BRP's review focused on potential "radiological" impact of Exelon's proposed EPU and we have no objections to the proposed amendment. The PA DEP will continue to conduct its independent review and assessment of plant operations at the Peach Atomic Power Station during the implementation of the EPU.

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 24, 2013 (78 FR 63506). 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 31, 2014 (79 FR 18073). 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) there is reasonable assurance that such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public.

9.0 REFERENCES

1. Exelon letter to NRC dated September 28, 2012, "Peach Bottom Atomic Power Station, Units 2 and 3, License Amendment Request - Extended Power Uprate" (ADAMS Accession No. ML122860201).

2. Exelon letter to NRC dated February 15, 2013, "Peach Bottom Atomic Power Station, Units 2 and 3, Supplemental Information and Corrections Supporting Request for License Amendment Request - Extended Power Uprate - Supplement No. 1" (ADAMS Accession No. ML13051A032).

3. Exelon letter to NRC dated May 7, 2013, "Peach Bottom Atomic Power Station, Units 2 and 3, Extended Power Uprate, Supplement 2 - Response to Request for Additional Information" (ADAMS Accession No. ML13129A143).

4. Exelon letter to NRC dated May 24, 2013, "Peach Bottom Atomic Power Station, Units 2 and 3, Extended Power Uprate License Amendment Request - Supplement 3, Response to Request for Additional Information - Extended Power Uprate" (ADAMS Accession No. ML13149A145).

5. Exelon letter to NRC dated June 4, 2013, "Peach Bottom Atomic Power Station, Units 2 and 3, Extended Power Uprate License Amendment Request - Supplement 4, Response to Request for Additional Information - Extended Power Uprate" (ADAMS Accession No. ML13156A368).

6. Exelon letter to NRC dated June 27, 2013, "Peach Bottom Atomic Power Station, Units 2 and 3, Supplemental Information Supporting Request for License Amendment Request - Extended Power Uprate - Supplement No. 5" (ADAMS Accession No. ML13182A025).

7. Exelon letter to NRC dated July 30, 2013, "Peach Bottom Atomic Power Station, Units 2 and 3, Extended Power Uprate License Amendment Request - Supplement 6, Response to Request for Additional Information - Extended Power Uprate" (ADAMS Accession No. ML13211A457).

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Attachment:
List of Acronyms

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Date: August 25, 2014

ATTACHMENT - LIST OF ACRONYMS

ACRONYM	DEFINITION
AAC	alternate alternating current source
ABA	Amplitude Based Algorithm
AC	alternating current
ACE	acoustic circuit model enhanced
ACM	acoustic circuit model
ADAMS	Agencywide Documents Access and Management System
ADS	automatic depressurization system
AEC	Atomic Energy Commission
AFT	as-found tolerance
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
AOR	analysis of record
AOV	air-operated valve
APLHGR	average planar linear heat generation rate
APRM	average power range monitor
ARI	alternate rod injection
ART	adjusted reference temperature
ASD	adjustable speed drive or alternate shutdown
ASDC	alternate shutdown cooling
ASME	American Society of Mechanical Engineers
AST	alternative source term
ASTM	American Society for Testing and Materials

ACRONYM	DEFINITION
ATSP	actual trip setpoint
ATWS	anticipated transient without scram
AV	allowable value
B&PV	Boiler and Pressure Vessel
B/U	bias and uncertainty
BOP	balance of plant
BPWS	banked position withdrawal sequence
BSP	backup stability protection
BTP	branch technical position
BTU	British thermal units
BUF	bump-up factor
BWR	boiling-water reactor
BWROG	Boiling Water Reactor Owners Group
BWRVIP	Boiling Water Reactor Vessels and Internals Project
cal/gm	calories per gram
CAP	containment accident pressure
CARV	cross around relief valve
CDF	core damage frequency
ΔCDF	change in core damage frequency
CDI	Continuum Dynamics Incorporated
cfm	cubic feet per minute
CFR	*Code of Federal Regulations*
CFS	condensate and feedwater system
CIC	coolant injection cooling
CLB	current licensing basis
CLTP	current licensed thermal power
CLTR	constant pressure power uprate licensing topical report
CO	condensation oscillation

ACRONYM	DEFINITION
COLR	core operating limit report
CPPU	constant pressure power uprate
CPR	critical power ratio
ΔCPR	change in critical power ratio
CR	control room
CRD	control rod drive
CRDA	control rod drop accident
CRGT	control rod guide tube
CRHE	control room habitability envelope
CRDM	control rod drive mechanism
CREV	control room emergency ventilation
CS	core spray
CSC	containment spray cooling
CST	condensate storage tank
CUF	cumulative usage factor
CVAP	Comprehensive Vibration Assessment Program
CWS	circulating water system
DBA	design-basis accident
DBLOCA	design-basis loss-of-coolant accident
DC	direct current
DIVOM	delta critical power ratio (CPR) over initial CPR versus oscillation magnitude
DSV	Dresser spring valve
DW	dead weight
EAB	exclusion area boundary
ECCS	emergency core cooling system
EDG	emergency diesel generator
EFDS	equipment and floor drain system
EFPY	effective full-power years

ACRONYM	DEFINITION
ELTR1	GE Licensing Topical Report NEDC-32424P-A
ELTR2	GE Licensing Topical Report NEDC-32523P-A
EMA	equivalent margin analysis
EOP	emergency operating procedure
EPG	Emergency Procedure Guidelines
EPRI	Electric Power Research Institute
EPU	extended power uprate
EQ	environmental qualification
ESF	engineered safety feature
ESFAS	engineered safety feature actuation system
ESW	emergency service water
ETAP	Electrical Transient Analysis Program
FAC	flow-accelerated corrosion
FE	finite element
FEM	finite-element model
FFWTR	final feedwater temperature reduction
FHA	fuel handling accident
FIV	flow-induced vibration
FIVE	Fire Induced Vulnerability Evaluation
FOL	facility operating license
FPCCS	fuel pool cooling and cleanup system
FPP	fire protection program
FR	*Federal Register*
FSSD	Fire Safe Shutdown Directive
ft-lb	foot-pound(s)
ft/s	feet per second
FW	feedwater
FWH	feedwater heater

ACRONYM	DEFINITION
FWHOOS	feedwater heater out of service
FWLB	Feedwater line break
GALL	Generic Aging Lessons Learned
Gd	Gadolinium
GDC	general design criterion/criteria
GE	General Electric
GEH	GE-Hitachi Nuclear Energy Americas LLC
GESTAR	General Electric Standard Application for Reactor Fuels
GGNS	Grand Gulf Nuclear Station
GL	generic letter
gpm	gallons per minute
GNF	Global Nuclear Fuel
GRA	Growth Rate Algorithm
GSU	generator step-up
GWMS	gaseous waste management systems
HCGS	Hope Creek Generating Station
HCOM	hot channel oscillation magnitude
HEP	human error probabilities
HFCL	High Flow Control Line
hp	horsepower
hr	hour
HELB	high-energy line break
HEPA	high-efficiency particulate air
HP	high pressure
HPCI	high-pressure coolant injection
HPCS	high-pressure core spray
HPSW	high-pressure service water
HPT	high-pressure turbine

ACRONYM	DEFINITION
HRA	human reliability analysis
HVAC	heating, ventilating, and air conditioning
HX	heat exchanger
Hz	Hertz
IASCC	irradiation-assisted stress-corrosion cracking
IBA	intermediate break analysis
ICA	Interim Corrective Actions
IEEE	Institute of Electrical and Electronics Engineers
IGSCC	intergranular stress-corrosion cracking
IMLTR	interim methods licensing topical report
IPBD	iso-phase bus duct
IPE	individual plant examination
IPEEE	individual plant examination of external event
ISFSI	independent spent fuel storage installation
ISI	inservice inspection
ISP	integrated surveillance program
IST	inservice testing
JI	jet impingement
kV	kilovolt(s)
LAR	license amendment request
LAZ	leave alone zone
LCO	limiting condition for operation
LEFM	leading edge flowmeter
LER	licensee event report
LERF	large early release frequency
LFWH	loss of feedwater heater
LHGR	linear heat generation rate
LLHS	light load handling system

ACRONYM	DEFINITION
LOCA	loss-of-coolant accident
LOCV	loss of condenser vacuum
LOFW	loss of feedwater
LOOP	loss of offsite power
LP	low pressure
LPCI	low-pressure coolant injection
LPSP	low power setpoint
LPT	low-pressure turbine
LPZ	low population zone
LPRM	local power range monitor
LRNBP	generator load rejection with steam bypass
LTR	licensing topical report
LTS	long-term stability
LTT	large transient testing
LWMS	liquid waste management system
M&E	mass and energy
MAAP	Modular Accident Analysis Program
MAPLHGR	maximum average planar linear heat generation rate
MASR	minimum alternating stress ratio
MBTU/hr	million British Thermal Units per hour
MC	main condenser
MCC	motor control center
MCES	main condenser evacuation system
MCO	moisture carryover
MCPR	minimum critical power ratio
MELB	moderate energy line break
MELC	moderate energy line crack
MELLLA	maximum extended load line limit analysis

ACRONYM	DEFINITION
MeV	mega electron volt
mg	milligram
Mlb/h	million pounds per hour
Mlbm/h	Million pounds mass per hour
mm	millimeter
MNGP	Monticello Nuclear Generating Plant
MOP	mechanical over power
MOV	motor-operated valve
MPSPCWL	maximum pressure suppression primary containment water level
mrem	millirem
MS	main steam
MSF	Modified Shape Function
MSIV	main steam isolation valve
MSIVC	main steam isolation valve closure
MSIVF	main steam isolation valve closure with flux scram
MSL	main steam line
MSLB	main steam line break
MSLBA	main steam line break accident
MSO	multiple spurious operations
MSSS	main steam supply system
MST	main steam tunnel
MUR	measurement uncertainty uprate
MVA	megavolt ampere(s)
MVAR	megavolt amperes reactive
MWe	megawatt(s) electric
MWt	megawatt(s) thermal
N-16	nitrogen-16
n/cm^2	neutron(s) per centimeter squared

ACRONYM	DEFINITION
NCL	Natural Circulation Line
NEI	Nuclear Energy Institute
NMP2	Nine Mile Point Nuclear Station, Unit 2
NPSH	net positive suction head
NPSHa	net positive suction head available
NPSHr	net positive suction head required
NRC	U.S. Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NSDC	normal shutdown cooling
NSSS	nuclear steam supply system
NUMARC	Nuclear Management and Resource Council, Inc.
O&M	Operation and Maintenance
OBE	operating basis earthquake
OEM	original equipment manufacturer
OLLHGR	linear heat generation rate operating limit
OLMCPR	operating limit minimum critical power ratio
OLTP	original licensed thermal power
OPRM	oscillation power range monitor
P-T	pressure-temperature
PAP	Power Ascension Program
PATP	Power Ascension and Test Program
PBAPS	Peach Bottom Atomic Power Station
PBDA	Period Based Detection Algorithm
PCF	pressure conversion factor
PCT	peak cladding temperature
PF	power factor
PJM	Pennsylvania, New Jersey, Maryland Interconnection, LLC
ppb	parts per billion

ACRONYM	DEFINITION
PORC	Plant Operations Review Committee
PRA	probabilistic risk assessment
PRFD	pressure regulator failure downscale
PRFO	pressure regulator failure to open
PRNM	power range neutron monitoring
PSD	power spectral density
psi	pounds per square inch
psia	pounds per square inch atmospheric
psid	pounds per square inch differential
psig	pounds per square inch gauge
PUSAR	power uprate safety analysis report
QA	Quality Assurance
QC	Quad Cities Nuclear Power Station
QC2	Quad Cities Nuclear Power Station, Unit 2
RAI	request for additional information
RBCCW	reactor building closed cooling water
RCIC	reactor core isolation cooling
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
rem	roentgen equivalent man
RFO	refueling outage
RFPT	reactor feedwater pump turbine
RG	regulatory guide
RHR	residual heat removal
RIPD	reactor internal pressure difference
RIS	regulatory issue summary
RLB	recirculation line break
RMS	root mean square

ACRONYM	DEFINITION
RPS	reactor protection system
RPT	recirculation pump trip
RPV	reactor pressure vessel
RRP	reactor recirculation pump
RRS	reactor recirculation system
RS	review standard
RSD	replacement steam dryer
RSLB	recirculation suction line break
RTP	rated thermal power
RVI	reactor vessel internals
RWCU	reactor water cleanup
RWM	rod worth minimizer
RWST	refueling water storage tank
SAFDLs	specified acceptable fuel design limits
SAG	Severe Accident Guidelines
SBA	small break accident
SBO	station blackout
SC	safety communication
SCF	stress concentration factor
scfh	standard cubic feet per hour
SDC	shutdown cooling
SDM	shutdown margin
SE	safety evaluation
SFP	spent fuel pool
SG	standards and guidelines
SGTS	standby gas treatment system
SIL	service information letter
SJAE	steam jet air ejector

ACRONYM	DEFINITION
SL	safety limit
SLC	standby liquid control
SLMCPR	safety limit minimum critical power ratio
SLO	single loop operation
SMA	seismic margins assessment
SMT	scale model testing
SORV	stuck-open relief valve
SPC	suppression pool cooling
SPDS	safety parameter display system
SPM	skirt protection model
SR	surveillance requirement
SRP	Standard Review Plan
SRSS	square-root-of-the-sum-of-the-squares
SRV	safety relief valve
SSC	structures, systems, and components
SSD	safe shutdown
SSE	safe-shutdown earthquake
SSES	Susquehanna Steam Electric Station
SSLB	small steam line break
SSV	spring safety valve
SV	safety valve
SW	service water
SWMS	solid waste management system
SWS	service water system
T-G	turbine-generator
TAF	top of active fuel
TBCCW	turbine building closed cooling water
TBS	turbine bypass system

ACRONYM	DEFINITION
TCD	thermal conductivity degradation
TCV	turbine control valve
TEDE	total effective dose equivalent
TID	total integrated dose
TOP	thermal over power
TRV	Target Rock valve
TS	technical specification
TSC	Technical Support Center
TSTF	Technical Specification Task Force
TSV	turbine stop valve
TSVC	turbine stop valve closure
TTNBP	turbine trip with steam bypass failure
UFSAR	updated final safety analysis report
UHS	ultimate heat sink
UPS	uninterruptible power supply
USE	upper-shelf energy
VPF	vane passing frequency
VY	Vermont Yankee Nuclear Power Station

The NRC staff has determined that its safety evaluation (SE) for the subject amendments contains proprietary information pursuant to Title 10 of the *Code of Federal Regulations,* Section 2.390. Accordingly, the NRC staff has prepared a redacted, publicly available, non-proprietary version of the SE. Both versions of the SE are enclosed. Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,
/RA/
Richard B. Ennis, Senior Project Manager
Plant Licensing Branch I-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-277 and 50-278

Enclosures:
1. Amendment No. 293 to Renewed DPR-44
2. Amendment No. 296 to Renewed DPR-56
3. Non-Proprietary SE
4. Proprietary SE

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