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

August 14, 2017

Mr. Joseph W. Shea, Vice President,
Nuclear Regulatory Affairs and Support Services
Tennessee Valley Authority
1101 Market Street, LP 3R-C
Chattanooga, TN 37402-2801

SUBJECT: BROWNS FERRY NUCLEAR PLANT, UNITS 1, 2, AND 3 - ISSUANCE OF AMENDMENTS REGARDING EXTENDED POWER UPRATE (CAC NOS. MF6741, MF6742, AND MF6743)

Dear Mr. Shea:

The Nuclear Regulatory Commission (NRC or the Commission) has issued the enclosed Amendment Nos. 299, 323, and 283, to Renewed Facility Operating License (RFOL) Nos. DPR-33, DPR-52, and DPR-68, for the Browns Ferry Nuclear Plant, Units 1, 2, and 3, respectively. These amendments are in response to Tennessee Valley Authority's (TVA's or the licensee's) application dated September 21, 2015, as supplemented by letters dated November 13, 2015; December 15, 2015 (two letters); December 18, 2015, February 16, 2016; March 8, 2016; March 9, 2016; March 24, 2016; March 28, 2016; April 4, 2016; April 5, 2016; April 14, 2016; April 22, 2016 (two letters); April 27, 2016; May 11, 2016; May 20, 2016 (two letters); May 27, 2016; June 9, 2016; June 17, 2016; June 20, 2016; June 24, 2016; July 13, 2016 (two letters); July 27, 2016; July 29, 2016 (two letters), August 3, 2016 (three letters), September 12, 2016; September 21, 2016; September 23, 2016; October 13, 2016; October 28, 2016; October 31, 2016; January 20, 2017; February 3, 2017; March 3, 2017; and June 12, 2017.

The amendments authorize an increase of maximum reactor core thermal power level for the Browns Ferry Nuclear Plant, Units 1, 2, and 3, to 3952 megawatts thermal (MWt). These license amendments represent an increase of approximately 14.3 percent above the current licensed thermal power level of 3458 MWt, which is an increase of approximately 20 percent above the original licensed thermal power level of 3293 MWt. The NRC considers the requested increase in power level to be an extended power uprate.

Enclosure 4 transmitted herewith contains Sensitive Unclassified Non-Safeguard Information. When separated from Enclosure 4, this document is decontrolled.

The NRC staff has completed its review of the information provided by the licensee. Enclosure 4 provides the staff's safety evaluation (SE). The staff has determined that its documented SE in Enclosure 4 contains proprietary information pursuant to Title 10 of the *Code of Federal Regulations* (10 CFR) 2.390, "Public Inspections, Exemptions, Requests for Withholding." Accordingly, the NRC staff has prepared a redacted, nonproprietary version (Enclosure 5). However, the NRC staff will delay placing the nonproprietary SE in the public document room for a period of 10 working days from the date of this letter to allow TVA to comment on any proprietary aspects. If you believe that any information in Enclosure 5 is proprietary, please identify such information line by line and define the basis pursuant to the criteria of 10 CFR 2.390. After 10 working days, the nonproprietary SE will be made publicly available.

A Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,

Farideh E. Saba

Farideh E. Saba, Senior Project Manager
Plant Licensing Branch II-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-259, 50-260, and 50-296

Enclosures:
1. Amendment No. 299 to DPR-33
2. Amendment No. 323 to DPR-52
3. Amendment No. 283 to DPR-68
4. Safety Evaluation (Proprietary Information)
5. Safety Evaluation (Nonproprietary Information)

cc: w/ Enclosures 1, 2, 3, and 5: Listserv **(10 days after issuance of the amendments to the licensee)**

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

TENNESSEE VALLEY AUTHORITY

DOCKET NO. 50-259

BROWNS FERRY NUCLEAR PLANT UNIT 1

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 299
Renewed License No. DPR-33

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

   A. The application for amendment by the Tennessee Valley Authority (the licensee) dated September 21, 2015, as supplemented by letters dated November 13, 2015; December 15, 2015 (two letters); December 18, 2015; February 16, 2016; March 8, 2016; March 9, 2016; March 24, 2016; March 28, 2016; April 4, 2016; April 5, 2016; April 14, 2016; April 22, 2016 (two letters); April 27, 2016; May 11, 2016; May 20, 2016 (two letters); May 27, 2016; June 9, 2016; June 17, 2016; June 20, 2016; June 24, 2016; July 13, 2016 (two letters); July 27, 2016; July 29, 2016 (two letters), August 3, 2016 (three letters); September 12, 2016; September 21, 2016; September 23, 2016; October 13, 2016; October 28, 2016; October 31, 2016; January 20, 2017; February 3, 2017; March 3, 2017; and June 12, 2017, 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 Renewed Facility Operating License (RFOL) and Technical Specifications as indicated in the attachment to this license amendment. Paragraphs 2.C.(1) and 2.C.(2) of RFOL No. DPR-33 are hereby amended as follows:

(1) Maximum Power Level

The licensee is authorized to operate the facility at steady state reactor core power levels not in excess of 3952 megawatts thermal.

(2) Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 299, are hereby incorporated in the renewed license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. Further, RFOL No. DPR-33 is amended by changes to Item 3 under "Transition License Condition" of paragraph 2.C.(13) of the license as follows:

   3. The licensee shall complete the implementation items as listed in Table S-3, "Implementation Items," of Tennessee Valley Authority letters CNL-15-191, dated September 8, 2015, and CNL-16-165, dated October 31, 2016, within 240 days after issuance of the license amendment unless that date falls within a scheduled refueling outage, then implementation will occur within 60 days after startup from that scheduled refueling outage. Implementation items 32 and 33 are associated with modifications and will be completed after all procedure updates, modifications, and training are complete.

4. In addition, RFOL No. DPR-33 is amended by the addition of new License Conditions 2.C.(18), "Potential Adverse Flow Effects"; 2.C.(19), "Neutron Absorber Monitoring Program"; and 2.C.(20), "Radiological Consequences Analyses Using Alternative Source Terms" as indicated in the attachment to this amendment.

5. This license amendment is effective as of its date of issuance and shall be implemented prior to startup from the refueling outage in the fall of 2018.

FOR THE NUCLEAR REGULATORY COMMISSION

Brian E. Holian, Acting Director
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Facility Operating
License and Technical Specifications

Date of Issuance: August 14, 2017

ATTACHMENT TO LICENSE AMENDMENT NO. 299

BROWNS FERRY NUCLEAR PLANT, UNIT 1

RENEWED FACILITY OPERATING LICENSE NO. DPR-33

DOCKET NO. 50-259

Replace the following pages of Renewed Facility Operating License No. DPR-33 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
5b	5b
6	6
--	6a
--	6b
--	6c
--	6d
--	6e
--	6f

Replace the following pages of 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
1.1-6	1.1-6
2.0-1	2.0-1
3.1-25	3.1-25
3.2-1	3.2-1
3.2-2	3.2-2
3.2-3	3.2-3
3.2-4	3.2-4
3.2-5	3.2-5
3.2-6	3.2-6
3.3-2	3.3-2
3.3-3	3.3-3
3.3-5	3.3-5
3.3-6	3.3-6
3.3-8	3.3-8
3.3-21	3.3-21
3.3-29	3.3-29
3.3-30	3.3-30
3.3-31	3.3-31
3.4-6	3.4-6

REMOVE	INSERT
3.6-41	3.6-41
3.7-16	3.7-16
4.0-2	4.0-2
5.0-20	5.0-20
--	5.0-21b

(3) Pursuant to the Act and 10 CFR Parts 30, 40, and 70, to receive, possess, and use at any time any byproduct, source, and special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(4) Pursuant to the Act and 10 CFR Parts 30, 40, and 70, to receive, possess, and use in amounts as required any byproduct, source, or special nuclear material without restriction to chemical or physical form for sample analysis or equipment and instrument calibration or associated with radioactive apparatus or components;

(5) Pursuant to the Act and 10 CFR Parts 30 and 70, to possess but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. This renewed operating 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, Sections 50.54 and 50.59 of Part 50, and Section 70.32 of Part 70; is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

The licensee is authorized to operate the facility at steady state reactor core power levels not in excess of 3952 megawatts thermal.

(2) Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 299, are hereby incorporated in the renewed operating license. The licensee shall operate the facility in accordance with the Technical Specifications.

For Surveillance Requirements (SRs) that are new in Amendment 234 to Facility Operating License DPR-33, the first performance is due at the end of the first surveillance interval that begins at implementation of the Amendment 234. For SRs that existed prior to Amendment 234, including SRs with modified acceptance criteria and SRs whose frequency of performance is being extended, the first performance is due at the end of the first surveillance interval that begins on the date the surveillance was last performed prior to implementation of Amendment 234.

2. Fire Protection Program Changes that Have No More than Minimal Risk Impact

   Prior NRC review and approval are not required for changes to the licensee's fire protection program that have been demonstrated to have no more than a minimal risk impact. The licensee may use its screening process as approved in the NRC Safety Evaluation dated October 28, 2015, to determine that certain fire protection program changes meet the minimal criterion. The licensee shall ensure that fire protection defense-in-depth and safety margins are maintained when changes are made to the fire protection program.

Transition License Conditions

1. Before achieving full compliance with 10 CFR 50.48(c), as specified by (2) below, risk-informed changes to the licensee's fire protection program may not be made without prior NRC review and approval unless the change has been demonstrated to have no more than a minimal risk impact, as described in (2) above.

2. The licensee shall implement the following modifications to its facility, as described in Table S-2, "Plant Modifications," of Tennessee Valley Authority letter CNL-15-191, dated September 8, 2015, to complete the transition to full compliance with 10 CFR 50.48(c) no later than the end of the second refueling outage (for each unit) following issuance of the license amendment. The licensee shall maintain appropriate compensatory measures in place until completion of these modifications.

3. The licensee shall complete the implementation items as listed in Table S-3, "Implementation Items," of Tennessee Valley Authority letters CNL-15-191, dated September 8, 2015; and CNL-16-165, dated October 31, 2016, within 240 days after issuance of the license amendment unless that date falls within a scheduled refueling outage, then implementation will occur within 60 days after startup from that scheduled refueling outage. Implementation items 32 and 33 are associated with modifications and will be completed after all procedure updates, modifications, and training are complete.

(14) The licensee shall maintain the Augmented Quality Program for the Standby Liquid Control System to provide quality control elements to ensure component reliability for the required alternative source term function defined in the Updated Final Safety Analyses Report (UFSAR).

(15) The licensee is required to confirm that the conclusions made in TVA's letter dated September 17, 2004, for the turbine building remain acceptable using seismic demand accelerations based on dynamic seismic analysis prior to the restart of Unit 1.

(16) Upon implementation of Amendment No. 275, adopting TSTF-448, Revision 3, the determination of control room envelope (CRE) unfiltered air inleakage as required by SR 3.7.3.4, in accordance with TS 5.5.13.c.(i), the assessment of the CRE habitability as required by TS 5.5.13.c.(ii), and the measure of CRE pressure as required by TS 5.5.13.d, shall be considered met.

Following Implementation:

(a) The first performance of SR 3.7.4.4, in accordance with TS 5.5.13.c.(i), shall be within a specific frequency of 6 years, plus the 18-month allowance of SR 3.0.2, as measured from November 10, 2003, the date of the most recent successful tracer gas test.

(b) The first performance of the periodic assessment of the Control Room Envelope (CRE) Habitability, Technical Specification 5.5.13.c.(ii), shall be within 9 months following the initial implementation of the TS Change. The next performance of the periodic assessment will be in a period specified by the CRE Program. That is 3 years from the last successful performance of the Technical Specification 5.5.13.c.(ii) tracer gas test.

(c) The first performance of the periodic measurement of CRE pressure, TS 5.5.13.d, shall be within 24 months, plus 180 days allowed by SR 3.0.2 as measured from the date of the most recent successful pressure measurement test.

(17) The fuel channel bow standard deviation component of the channel bow model uncertainty used by ANP-10307PA, "AREVA MCPR Safety Limit Methodology for Boiling Water Reactors, Revision 0," (i.e., TS 5.6.5.b.11) to determine the Safety Limit Minimum Critical Power Ratio shall be increased by the ratio of channel fluence gradient to the nearest channel fluence gradient bound of the channel measurement database, when applied to channels with fluence gradients outside the bounds of the measurement database from which the model uncertainty is determined. This license condition will be effective upon the implementation of Amendment No. 285.

(18) Potential Adverse Flow Effects

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) for initial power ascension from 3458 MWt to the extended power uprate (EPU) level of 3952 MWt.

(a) The following requirements are placed on operation of the facility before and during the initial power ascension:

1. TVA shall provide a Power Ascension Test (PAT) Plan for the BFN Unit 1 steam dryer testing. The PAT plan shall be submitted to the NRC Project Manager no later than 10 days before startup.

2. TVA shall monitor the main steamline (MSL) strain gauges at a minimum of three power levels up to 3458 MWt. If the number of

active MSL strain gauges is less than two strain gauges (180 degrees apart) at any of the eight MSL locations, TVA will stop power ascension and repair/replace the damaged strain gauges and only then resume power ascension.

3. At least 90 days prior to the start of the BFN Unit 1 EPU outage, TVA shall revise the BFN Unit 1 replacement steam dryer (RSD) analysis utilizing the BFN Unit 3 on-dryer strain gauge based end-to-end bias and uncertainties (B&Us) at EPU conditions, and submit the information including the updated limit curves and a list of dominant frequencies for BFN Unit 1, to the NRC as a report in accordance with 10 CFR 50.4.

   a. If the on-dryer instrumentation was not available when BFN Unit 3 reached a power level of 3458 MWt and the BFN-specific bias and uncertainty data and transfer function could not be developed, the predicted dryer loads during the BFN Unit 1 power ascension will be calculated with the Plant Based Load Evaluation Method 2 transfer function used in the steam dryer design analyses for EPU. The acceptance limits will be based on BFN Unit 3 steam dryer confirmatory stress analysis results using the MSL strain gauge data collected at EPU conditions. The acceptance limits will ensure the steam dryer stress margins remain above the minimum alternating stress ratio (MASR) determined in the BFN Unit 3 steam dryer EPU confirmatory analyses.

4. TVA shall evaluate the BFN Unit 1 limit curves prepared in item (a)3 above based on new MSL strain gauge data collected following the BFN Unit 1 EPU outage at or near 3458 MWt. If the limit curves change, the new post-EPU outage limit curves shall be provided to the NRC Project Manager. TVA shall not increase power above 3458 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.

5. TVA shall monitor the MSL strain gauges during power ascension above 3458 MWt for increasing pressure fluctuations in the steam lines. Upon the initial increase of power above 3458 MWt until reaching 3952 MWt, TVA shall collect data from the MSL strain gauges at nominal 2.5 percent of 3458 MWt (approximately 86 MWt) increments and evaluate steam dryer performance based on this data.

6. During power ascension at each nominal 2.5 percent power level above 3458 MWt (approximately 86 MWt), TVA shall compare the MSL data to the approved limit curves based on end-to-end B&Us from the BFN Unit 3 benchmarking at EPU conditions and determine the MASR.

7. TVA shall hold the facility at approximately 3630 MWt and 3803 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 7.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, to the NRC Project Manager, upon completion of the evaluation for each of the hold points.

   f. TVA 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.

8. If any frequency peak from the MSL strain gauge data exceeds the Level 1 limit curves, TVA shall return the facility to a power level at which the limit curve is not exceeded. TVA shall resolve the discrepancy, evaluate and document the continued structural integrity of the steam dryer, and provide that documentation to the NRC Project Manager prior to further increases in reactor power. If a revised stress analysis is performed and new limit curves are developed, then TVA 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 Item (b)1 below.

(b) TVA shall implement the following actions for the initial power ascension from 3458 MWt to 3952 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 3458 MWt, TVA 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 Item (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 BFN Unit 3 EPU measurements.

b. Use of scaling factors associated with all of the safety relief valve acoustic resonances as estimated in the predictive analysis or in-plant data acquired during power ascension.

2. After reaching 3952 MWt, TVA shall obtain measurements from the MSL strain gauges and establish the steam dryer flow-induced vibration load fatigue margin for the facility and update the steam dryer stress report. These data will be provided to the NRC staff as described below in item (e).

(c) TVA shall prepare the EPU PAT Plan to include the following.

1. The MSL strain gauge limit curves to be applied for evaluating steam dryer performance, based on end-to-end B&Us from BFN Unit 3 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 3458 MWt.

10. Identify the NRC Project Manager as the NRC point of contact for providing PAT plan information during power ascension.

11. Methodology for updating limit curves.

(d) The following key attributes of the PAT Plan shall not be made less restrictive without prior NRC approval:

1. During initial power ascension testing above 3458 MWt, each of the two hold points shall be at increments of approximately 5 percent of 3458 MWt.

2. Level 1 performance criteria.

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

Changes to other aspects of the PAT Plan may be made in accordance with the guidance of NEI 99-04, "Guidelines for Managing NRC Commitments," issued July 1999.

(e) Following the data collection and evaluation at the EPU power level, TVA shall provide 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 BFN Unit 3 benchmarking at EPU conditions. The report shall be submitted to NRC within 90 days of the completion of EPU power ascension testing for BFN Unit 1. Should the results of this stress analysis indicate the allowable stress in any part of the steam dryer is exceeded, TVA shall reduce power to a level at which the allowable stress is met, evaluate the steam dryer integrity, and assess any shortcomings in the predictive analysis. The results of this evaluation, including a recommended resolution of any identified issues and a demonstration of steam dryer integrity at EPU conditions, shall be provided to the NRC for review and approval prior to return to EPU conditions.

(f) Following the data collection and evaluation at the EPU power level, TVA shall provide a vibration summary report to the NRC. The summary report shall be submitted to the NRC within 90 days of the completion of EPU power ascension testing for BFN Unit 1. The vibration summary report shall include the information in items (f)1 through (f)3, as follows:

1. Vibration data for piping and valve locations deemed prone to vibration and vibration monitoring locations identified in Attachment 45 to the EPU application dated September 21, 2015, including the identified locations associated with MSLs, Feedwater Lines, Safety Relief Valves and the Main Steam Isolation Valves.

2. An evaluation of the measured vibration data collected in item (f)1 above compared against acceptance limits.

3. Vibration values and associated acceptance limits at approximately 3630 MWt, 3803 MWt, and 3952 MWt using the data collected in item (f)1, above.

(g) 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 Boiling Water Reactor Vessels and Internals Project (BWRVIP)-139A (Steam Dryer Inspection and Flaw Evaluation Guidelines) and General Electric (GE) inspection guidelines (SIL 644, BWR Steam Dryer Integrity).

(h) 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 to the NRC within 90 days following startup from each of the first two respective refueling outages.

(i) 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 items (g) and (h), 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 item (i).

(19) Neutron Absorber Monitoring Program

The licensee shall, at least once every ten years, withdraw a neutron absorber coupon from the spent fuel pool and perform Boron-10 (B-10) areal density measurement on the coupon. Based on the results of the B-10 areal density measurement, the licensee shall perform any technical evaluations that may be necessary and take appropriate actions using relevant regulatory and licensing processes.

(20) Radiological Consequences Analyses Using Alternative Source Terms

TVA shall perform facility and licensing basis modifications to resolve the non-conforming/degraded condition associated with the Alternate Leakage Treatment pathway such that the current licensing basis dose calculations (approved in License Amendment Nos. 251/282 (Unit 1), 290/308 (Unit 2) and 249/267 (Unit 3)) would remain valid. These facility and licensing basis modifications shall be complete prior to initial power ascension above 3458 MWt.

D. The UFSAR supplement, as revised, submitted pursuant to 10 CFR 54.21(d), shall be included in the next scheduled update to the UFSAR required by 10 CFR 50.71(e)(4) following the issuance of this renewed operating license. Until that update is complete, TVA may make changes to the programs and activities described in the supplement without prior Commission approval, provided that TVA evaluates such changes pursuant to the criteria set forth in 10 CFR 50.59 and otherwise complies with the requirements in that section.

E. The UFSAR supplement, as revised, describes certain future activities to be completed prior to the period of extended operation. TVA shall complete these activities no later than December 20, 2013, and shall notify the NRC in writing when implementation of these activities is complete and can be verified by NRC inspection.

F. All capsules in the reactor vessel that are removed and tested must meet the test procedures and reporting requirements of the most recent NRC-approved version of the Boiling Water Reactor Vessels and Internals Project (BWRVIP) Integrated Surveillance Program (ISP) appropriate for the configuration of the specimens in the capsule. Any changes to the BWRVIP ISP capsule withdrawal schedule, including spare capsules, must be approved by the NRC prior to implementation. All capsules placed in storage

1.1 Definitions (continued)

OPERABLE - OPERABILITY	A system, subsystem, division, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, division, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).
PHYSICS TESTS	PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation. These tests are: a. Described in Section 13.10, Refueling Test Program; of the FSAR; b. Authorized under the provisions of 10 CFR 50.59; or c. Otherwise approved by the Nuclear Regulatory Commission.
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of 3952 MWt.

(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 < 585 psig or core flow < 10% rated core flow:

THERMAL POWER shall be ≤ 23% RTP.

2.1.1.2 With the reactor steam dome pressure ≥ 585 psig and core flow ≥ 10% rated core flow:

MCPR shall be ≥ 1.06 for two recirculation loop operation or ≥ 1.08 for single 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.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
	Verify the concentration and temperature of boron in solution are within the limits of Figure 3.1.7-1.	Once within 8 hours after discovery that SPB concentration is > 9.2% by weight AND 12 hours thereafter
SR 3.1.7.5	Verify the minimum quantity of Boron-10 in the SLC solution tank and available for injection is ≥ 203 pounds.	31 days
SR 3.1.7.6	Verify the SLC conditions satisfy the following equation: $\frac{(C)(Q)(E)}{(8.7\ \text{wt.}\%)(50\ \text{gpm})(94\ \text{atom}\%)} \geq 1$ where, C = sodium pentaborate solution concentration (weight percent) Q = pump flow rate (gpm) E = Boron-10 enrichment (atom percent Boron-10)	31 days AND Once within 24 hours after water or boron is added to the solution
SR 3.1.7.7	Verify each pump develops a flow rate ≥ 39 gpm at a discharge pressure ≥ 1325 psig.	24 months

(continued)

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 AND 24 hours thereafter

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 24 hours thereafter
SR 3.2.2.2	Determine the MCPR limits.	Once within 72 hours after each completion of SR 3.1.4.1 AND Once within 72 hours after each completion of SR 3.1.4.2

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 24 hours thereafter

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One or more 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% 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
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

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.	24 hours
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.	7 days
SR 3.3.1.1.3	----------NOTE---------- Not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. ---------- Perform CHANNEL FUNCTIONAL TEST.	7 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.10	Perform CHANNEL CALIBRATION.	184 days
SR 3.3.1.1.11	(Deleted)	
SR 3.3.1.1.12	Perform CHANNEL FUNCTIONAL TEST.	24 months
SR 3.3.1.1.13	----------NOTE---------- Neutron detectors are excluded. ---------- Perform CHANNEL CALIBRATION.	 24 months
SR 3.3.1.1.14	Perform LOGIC SYSTEM FUNCTIONAL TEST.	24 months
SR 3.3.1.1.15	Verify Turbine Stop Valve — Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure — Low Functions are not bypassed when THERMAL POWER is ≥ 26% RTP.	24 months
SR 3.3.1.1.16	----------NOTE---------- For Function 2.a, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. ---------- Perform CHANNEL FUNCTIONAL TEST.	 184 days
SR 3.3.1.1.17	Verify OPRM is not bypassed when APRM Simulated Thermal Power is ≥ 23% and recirculation drive flow is < 60% of rated recirculation drive flow.	24 months

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. Intermediate Range Monitors					
a. Neutron Flux - High	2	3	G	SR 3.3.1.1.1 SR 3.3.1.1.3 SR 3.3.1.1.5 SR 3.3.1.1.6 SR 3.3.1.1.9 SR 3.3.1.1.14	≤ 120/125 divisions of full scale
	5[a]	3	H	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.9 SR 3.3.1.1.14	≤ 120/125 divisions of full scale
b. Inop	2	3	G	SR 3.3.1.1.3 SR 3.3.1.1.14	NA
	5[a]	3	H	SR 3.3.1.1.4 SR 3.3.1.1.14	NA
2. Average Power Range Monitors					
a. Neutron Flux - High, Setdown	2	3[b]	G	SR 3.3.1.1.1 SR 3.3.1.1.6 SR 3.3.1.1.7 SR 3.3.1.1.13 SR 3.3.1.1.16	≤ 13% RTP
b. Flow Biased Simulated Thermal Power - High	1	3[b]	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.7 SR 3.3.1.1.13 SR 3.3.1.1.16	≤ 0.55 W + 65.5% RTP and ≤ 120% RTP[c]
c. Neutron Flux - High	1	3[b]	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.7 SR 3.3.1.1.13 SR 3.3.1.1.16	≤ 120% RTP

(continued)

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

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

(c) [0.55 W + 65.5% - 0.55 Δ W] RTP when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating."

Table 3.3.1.1-1 (page 3 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
7. Scram Discharge Volume Water Level - High (continued)					
b. Float Switch	1,2	2	G	SR 3.3.1.1.8 SR 3.3.1.1.13 SR 3.3.1.1.14	≤ 46 gallons
	5(a)	2	H	SR 3.3.1.1.8 SR 3.3.1.1.13 SR 3.3.1.1.14	≤ 46 gallons
8. Turbine Stop Valve - Closure	≥ 26% RTP	4	E	SR 3.3.1.1.8 SR 3.3.1.1.13 SR 3.3.1.1.14 SR 3.3.1.1.15	≤ 10% closed
9. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low(d)	≥ 26% RTP	2	E	SR 3.3.1.1.8 SR 3.3.1.1.13 SR 3.3.1.1.14 SR 3.3.1.1.15	≥ 550 psig
10. Reactor Mode Switch - Shutdown Position	1,2	1	G	SR 3.3.1.1.12 SR 3.3.1.1.14	NA
	5(a)	1	H	SR 3.3.1.1.12 SR 3.3.1.1.14	NA
11. Manual Scram	1,2	1	G	SR 3.3.1.1.8 SR 3.3.1.1.14	NA
	5(a)	1	H	SR 3.3.1.1.8 SR 3.3.1.1.14	NA
12. RPS Channel Test Switches	1,2	2	G	SR 3.3.1.1.4	NA
	5(a)	2	H	SR 3.3.1.1.4	NA

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

(d) During instrument calibrations, if the As Found channel setpoint is conservative with respect to the Allowable Value but outside its acceptable As Found band as defined by its associated Surveillance Requirement procedure, then there shall be an initial determination to ensure confidence that the channel can perform as required before returning the channel to service in accordance with the Surveillance. If the As Found instrument channel setpoint is not conservative with respect to the Allowable Value, the channel shall be declared inoperable.

Prior to returning a channel to service, the instrument channel setpoint shall be calibrated to a value that is within the acceptable As Left tolerance of the setpoint; otherwise, the channel shall be declared inoperable.

The nominal Trip Setpoint shall be specified on design output documentation which is incorporated by reference in the Updated Final Safety Analysis Report. The methodology used to determine the nominal Trip Setpoint, the predefined As Found Tolerance, and the As Left Tolerance band, and a listing of the setpoint design output documentation shall be specified in Chapter 7 of the Updated Final Safety Analysis Report.

3.3 INSTRUMENTATION

3.3.2.2 Feedwater and Main Turbine High Water Level Trip Instrumentation

LCO 3.3.2.2 Two channels of feedwater and main turbine high water level trip instrumentation per trip system 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 feedwater and main turbine high water level trip channels inoperable, in one trip system.	A.1	Place channel(s) in trip.	7 days
B. One or more feedwater and main turbine high water level trip channels inoperable in each trip system.	B.1	Restore feedwater and main turbine high water level trip capability.	2 hours
C. Required Action and associated Completion Time not met.	C.1	Reduce THERMAL POWER to < 23% RTP.	4 hours

3.3 INSTRUMENTATION

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

LCO 3.3.4.1

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

c. LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)," limits for an inoperable EOC-RPT, as specified in the COLR, are made applicable.

APPLICABILITY: THERMAL POWER ≥ 26% RTP.

ACTIONS

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

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more channels inoperable.	A.1	Restore channel to OPERABLE status.	72 hours
	OR		
	A.2	----------NOTE---------- Not applicable if inoperable channel is the result of an inoperable breaker. ---------- Place channel in trip.	 72 hours
B. One or more Functions with EOC-RPT trip capability not maintained. AND MCPR and LHGR limits for inoperable EOC-RPT not made applicable.	B.1	Restore EOC-RPT trip capability.	2 hours
	OR		
	B.2	Apply MCPR and LHGR limits for inoperable EOC-RPT as specified in the COLR.	2 hours
C. Required Action and associated Completion Time not met.	C.1	Reduce THERMAL POWER to < 26% 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 3.3.4.1.1	Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.4.1.2	Verify TSV - Closure and TCV Fast Closure, Trip Oil Pressure - Low Functions are not bypassed when THERMAL POWER is ≥ 26% RTP.	24 months
SR 3.3.4.1.3	Perform CHANNEL CALIBRATION. The Allowable Values shall be: TSV - Closure: ≤ 10% closed; and TCV Fast Closure, Trip Oil Pressure - Low: ≥ 550 psig.	24 months
SR 3.3.4.1.4	Perform LOGIC SYSTEM FUNCTIONAL TEST including breaker actuation.	24 months

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.	24 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.3.1.1	Verify ≥ 2615 gal of liquid nitrogen are contained in each nitrogen storage tank.	31 days
SR 3.6.3.1.2	Verify each CAD 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.	31 days

3.7 PLANT SYSTEMS

3.7.5 Main Turbine Bypass System

LCO 3.7.5 The Main Turbine Bypass System shall be OPERABLE.

OR

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; and

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

4.0 DESIGN FEATURES (continued)

4.3 Fuel Storage

4.3.1 Criticality

4.3.1.1 The spent fuel storage racks are designed and shall be maintained with:

a. $k_{eff} \leq 0.95$ if fully flooded with unborated water, which includes an allowance for uncertainties as described in Section 10.3 of the FSAR; and

b. Fuel assemblies having a maximum k-infinity of 0.8825 in the normal spent fuel pool storage rack configuration; and

c. A nominal 6.563 inch center to center distance between fuel assemblies placed in the storage racks.

4.3.1.2 The new fuel storage vault shall not be used for fuel storage. New fuel shall be stored in the spent fuel storage racks.

(continued)

5.5 Programs and Manuals

5.5.11 Safety Function Determination Program (SFDP) (continued)

A loss of safety function exists when, assuming no concurrent single failure, a safety function assumed in the accident analysis cannot be performed. For the purpose of this program, a loss of safety function may exist when a support system is inoperable, and:

a. A required system redundant to system(s) supported by the inoperable support system is also inoperable; or

b. A required system redundant to system(s) in turn supported by the inoperable supported system is also inoperable; or

c. A required system redundant to support system(s) for the supported systems (a) and (b) above is also inoperable.

The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

5.5.12 Primary Containment Leakage Rate Testing Program

A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995.

The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is 49.1 psig. The maximum allowable primary containment leakage rate, L_a, shall be 2% of primary containment air weight per day at P_a.

(continued)

5.5 Programs and Manuals

5.5.14 Residual Heat Removal (RHR) Heat Exchanger Performance Monitoring Program

This program is established to ensure that the RHR heat exchangers are maintained in a condition that meets or exceeds the minimum performance capability assumed in containment analyses, which support not taking credit for containment accident pressure in the NPSH analyses. The RHR heat exchanger testing and determination of overall uncertainty in the fouling resistance shall be in accordance with the guidelines in EPRI report, EPRI 3002005340, Service Water Heat Exchanger Test Guidelines, May 2015. This program establishes the following attributes.

a. The program establishes provisions to periodically monitor RHR heat exchanger thermal performance. The program includes frequency of monitoring and the methodology considers uncertainty of the result.

b. The program establishes and controls acceptance criteria for RHR heat exchanger worst fouling resistance and number of plugged tubes.

c. The program establishes limitations and allows for compensatory actions if degraded performance is observed.

d. Changes to the program shall be made under appropriate administrative review.

e. Details of the program including program limitations, compensatory actions for degraded performance, testing method, data acquisition method, data reduction method, overall uncertainty determination method, thermal performance analysis, acceptance criteria, and computer programs used that meet the 10 CFR 50 Appendix B, and 10 CFR 21 requirements are described in the UFSAR.

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

TENNESSEE VALLEY AUTHORITY

DOCKET NO. 50-260

BROWNS FERRY NUCLEAR PLANT, UNIT 2

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 323
Renewed License No. DPR-52

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

   A. The application for amendment by the Tennessee Valley Authority (the licensee) dated September 21, 2015, as supplemented by letters dated November 13, 2015; December 15, 2015 (two letters); December 18, 2015; February 16, 2016; March 8, 2016; March 9, 2016; March 24, 2016; March 28, 2016; April 4, 2016; April 5, 2016; April 14, 2016; April 22, 2016 (two letters); April 27, 2016; May 11, 2016; May 20, 2016 (two letters); May 27, 2016; June 9, 2016; June 17, 2016; June 20, 2016; June 24, 2016; July 13, 2016 (two letters); July 27, 2016; July 29, 2016 (two letters), August 3, 2016 (three letters); September 12, 2016; September 21, 2016; September 23, 2016; October 13, 2016; October 28, 2016; October 31, 2016; January 20, 2017; February 3, 2017; March 3, 2017; and June 12, 2017, 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 Renewed Facility Operating License (RFOL) and Technical Specifications as indicated in the attachment to this license amendment. Paragraphs 2.C.(1) and 2.C.(2) of RFOL No. DPR-52 are hereby amended as follows:

(1) Maximum Power Level

The licensee is authorized to operate the facility at steady state reactor core power levels not in excess of 3952 megawatts thermal.

(2) Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 323, are hereby incorporated in the renewed operating license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. Further, RFOL No. DPR-52 is amended by changes to Item 3 under "Transition License Condition" of paragraph 2.C.(13) of the license as follows:

   3. The licensee shall complete the implementation items as listed in Table S-3, "Implementation Items," of Tennessee Valley Authority letters CNL-15-191, dated September 8, 2015, and CNL-16-165, dated October 31, 2016, within 240 days after issuance of the license amendment unless that date falls within a scheduled refueling outage, then implementation will occur within 60 days after startup from that scheduled refueling outage. Implementation items 32 and 33 are associated with modifications and will be completed after all procedure updates, modifications, and training are complete.

4. In addition, RFOL No. DPR-33 is amended by the addition of new License Conditions 2.C.(18), "Potential Adverse Flow Effects"; 2.C.(19), "Neutron Absorber Monitoring Program"; and 2.C.(20), "Radiological Consequences Analyses Using Alternative Source Terms," as indicated in the attachment to this amendment.

5. This license amendment is effective as of its date of issuance and shall be implemented prior to startup from the refueling outage in the spring of 2019.

FOR THE NUCLEAR REGULATORY COMMISSION

Brian E. Holian, Acting Director
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Facility Operating
License and Technical Specifications

Date of Issuance: August 14, 2017

ATTACHMENT TO LICENSE AMENDMENT NO. 323

BROWNS FERRY NUCLEAR PLANT, UNIT 2

RENEWED FACILITY OPERATING LICENSE NO. DPR-52

DOCKET NO. 50-260

Replace the following pages of Renewed Facility Operating License No. DPR-52 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
5b	5b
6	6
--	6a
--	6b
--	6c
--	6d
--	6e
--	6f

Replace the following pages of 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
1.1-6	1.1-6
2.0-1	2.0-1
3.1-25	3.1-25
3.2-1	3.2-1
3.2-2	3.2-2
3.2-3	3.2-3
3.2-4	3.2-4
3.2-5	3.2-5
3.2-6	3.2-6
3.3-2	3.3-2
3.3-4	3.3-4
3.3-6	3.3-6
3.3-7	3.3-7
3.3-9	3.3-9
3.3-22	3.3-22
3.3-30	3.3-30
3.3-31	3.3-31
3.3-32	3.3-32
3.4-6	3.4-6

REMOVE	INSERT
3.6-41	3.6-41
3.7-1	3.7-1
3.7-2	3.7-2
3.7-3	3.7-3
3.7-4	3.7-4
3.7-5	3.7-5
3.7-6	3.7-6
3.7-8	3.7-8
3.7-17	3.7-17
4.0-2	4.0-2
5.0-21	5.0-21
---	5.0-21b

sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(4) Pursuant to the Act and 10 CFR Parts 30, 40, and 70, to receive, possess, and use in amounts as required any byproduct, source, or special nuclear material without restriction to chemical or physical form for sample analysis or equipment and instrument calibration or associated with radioactive apparatus or components;

(5) Pursuant to the Act and 10 CFR Parts 30 and 70, to possess but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. This renewed operating license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations in 0 CFR Chapter I: Part 20, Section 30.34 of Part 30, Section 40.41 of Part 40, Sections 50.54 and 50.59 of Part 50, and Section 70.32 of Part 70; is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

The licensee is authorized to operate the facility at steady state reactor core power levels not in excess of 3952 megawatts thermal.

(2) Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 323, are hereby incorporated in the renewed operating license. The licensee shall operate the facility in accordance with the Technical Specifications.

For Surveillance Requirements (SRs) that are new in Amendment 253 to Facility Operating License DPR-52, the first performance is due at the end of the first surveillance interval that begins at implementation of the Amendment 253. For SRs that existed prior to Amendment 253, including SRs with modified acceptance criteria and SRs whose frequency of performance is being extended, the first performance is due at the end of the first surveillance interval that begins on the date the surveillance was last performed prior to implementation of Amendment 253.

(3) The licensee is authorized to relocate certain requirements included in Appendix A and the former Appendix B to licensee-controlled documents. Implementation of this amendment shall include the relocation of these requirements to the appropriate documents, as described in the licensee's

- Automatic and Manual Water-Based Fire Suppression Systems (Section 3.9);
- Gaseous Fire Suppression Systems (Section 3.10); and
- Passive Fire Protection Features (Section 3.11).

This License Condition does not apply to any demonstration of equivalency under Section 1.7 of NFPA 805.

1. Fire Protection Program Changes that Have No More than Minimal Risk Impact

   Prior NRC review and approval are not required for changes to the licensee's fire protection program that have been demonstrated to have no more than a minimal risk impact. The licensee may use its screening process as approved in the NRC Safety Evaluation dated October 28, 2015, to determine that certain fire protection program changes meet the minimal criterion. The licensee shall ensure that fire protection defense-in-depth and safety margins are maintained when changes are made to the fire protection program.

Transition License Conditions

1. Before achieving full compliance with 10 CFR 50.48(c), as specified by (2) below, risk-informed changes to the licensee's fire protection program may not be made without prior NRC review and approval unless the change has been demonstrated to have no more than a minimal risk impact, as described in (2) above.

2. The licensee shall implement the following modifications to its facility, as described in Table S-2, "Plant Modifications," of Tennessee Valley Authority letter CNL-15-191, dated September 8, 2015, to complete the transition to full compliance with 10 CFR 50.48(c) no later than the end of the second refueling outage (for each unit) following issuance of the license amendment. The licensee shall maintain appropriate compensatory measures in place until completion of these modifications.

3. The licensee shall complete the implementation items as listed in Table S-3, "Implementation Items," of Tennessee Valley Authority letters CNL-15-191, dated September 8, 2015; and CNL-16-165, dated October 31, 2016, within 240 days after issuance of the license amendment unless that date falls within a scheduled refueling outage, then implementation will occur within 60 days after startup from that scheduled refueling outage. Implementation items 32 and 33 are associated with modifications and will be completed after all procedure updates, modifications, and training are complete.

(15) The licensee shall maintain the Augmented Quality Program for the Standby Liquid Control System to provide quality control elements to ensure component reliability for the required alternative source term function defined in the Updated Final Safety Analysis Report (UFSAR).

(16) Upon complementation of Amendment No. 302, adopting TSTF-448, Revision 3, the determination of control room envelope (CRE) unfiltered air inleakage as required by SR 3. 7.3.4, in accordance with TS 5.5.13.c(i), the assessment of the CRE habitability as required by TS 5.5.13.c(ii), and the measure of CRE pressure as required by TS 5.5.13.d, shall be considered met.

Following implementation:

(a) The first performance of SR 3.7.4.4, in accordance with TS 5.5.13.c(i), shall be within a specific frequency of 6 years, plus the 18-month allowance of SR 3.0.2, as measured from November 10, 2003, the date of the most recent successful tracer gas test.

(b) The first performance of the periodic assessment of the Control Room Envelope (CRE) Habitability, Technical Specification 5.5.13.c(ii), shall be within 9 months following the initial implementation of the TS change. The next performance of the periodic assessment will be in a period specified by the CRE Program. That is 3 years from the last successful performance of the Technical Specification 5.5.13.c(ii) tracer gas test.

(c) The first performance of the periodic measurement of CRE pressure, TS 5.5.13.d, shall be with 24 months, plus 180 days allowed by SR 3.0.2 as measured from the date of the most recent successful pressure measurement test.

(17) The fuel channel bow standard deviation component of the channel bow model uncertainty used by ANP-10307PA, "AREVA MCPR Safety Limit Methodology for Boiling Water Reactors, Revision 0," (i.e., TS 5.6.5.b.11) to determine the Safety Limit Minimum Critical Power Ratio shall be increased by the ratio of channel fluence gradient to the nearest channel fluence gradient bound of the channel measurement database, when applied to channels with fluence gradients outside the bounds of the measurement database from which the model uncertainty is determined. This license condition will be effective upon the implementation of Amendment No. 311.

(18) Potential Adverse Flow Effects

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) for initial power ascension from 3458 MWt to the extended power uprate (EPU) level of 3952 MWt.

(a) The following requirements are placed on operation of the facility before and during the initial power ascension:

1. TVA shall provide a Power Ascension Test (PAT) Plan for the BFN Unit 2 steam dryer testing. The PAT plan shall be submitted to the NRC Project Manager no later than 10 days before start-up.

2. TVA shall monitor the main steamline (MSL) strain gauges at a minimum of three power levels up to 3458 MWt. If the number of active MSL strain gauges is less than two strain gauges (180 degrees apart) at any of the eight MSL locations, TVA will stop power ascension and

repair/replace the damaged strain gauges and only then resume power ascension.

3. At least 90 days prior to the start of the BFN Unit 2 EPU outage, TVA shall revise the BFN Unit 2 replacement steam dryer (RSD) analysis utilizing the BFN Unit 3 on-dryer strain gauge based end-to-end bias and uncertainties (B&Us) at EPU conditions, and submit the information including the updated limit curves and a list of dominant frequencies for BFN Unit 2, to the NRC as a report in accordance with 10 CFR 50.4.

   a. If the on-dryer instrumentation was not available when BFN Unit 3 reached a power level of 3458 MWt and the BFN-specific B&U data and transfer function could not be developed, the predicted dryer loads during the BFN Unit 2 power ascension will be calculated with the Plant Based Load Evaluation Method 2 transfer function used in the steam dryer design analyses for EPU. The acceptance limits will be based on BFN Unit 3 steam dryer confirmatory stress analysis results using the MSL strain gauge data collected at EPU conditions. The acceptance limits will ensure the steam dryer stress margins remain above the minimum alternating stress ratio (MASR) determined in the BFN Unit 3 steam dryer EPU confirmatory analyses.

4. TVA shall evaluate the BFN Unit 2 limit curves prepared in item (a)3 above based on new MSL strain gauge data collected following the BFN Unit 2 EPU outage at or near 3458 MWt. If the limit curves change, the new post-EPU outage limit curves shall be provided to the NRC Project Manager. TVA shall not increase power above 3458 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.

5. TVA shall monitor the MSL strain gauges during power ascension above 3458 MWt for increasing pressure fluctuations in the steam lines. Upon the initial increase of power above 3458 MWt until reaching 3952 MWt, TVA shall collect data from the MSL strain gauges at nominal 2.5 percent of 3458 MWt (approximately 86 MWt) increments and evaluate steam dryer performance based on this data.

6. During power ascension at each nominal 2.5 percent power level above 3458 MWt (approximately 86 MWt), TVA shall compare the MSL data to the approved limit curves based on end-to-end B&Us from the BFN Unit 3 benchmarking at EPU conditions and determine the MASR.

7. TVA shall hold the facility at approximately 3630 MWt and 3803 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 7.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, to the NRC Project Manager, upon completion of the evaluation for each of the hold points.

   f. TVA 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.

8. If any frequency peak from the MSL strain gauge data exceeds the Level 1 limit curves, TVA shall return the facility to a power level at which the limit curve is not exceeded. TVA shall resolve the discrepancy, evaluate and document the continued structural integrity of the steam dryer, and provide that documentation to the NRC Project Manager prior to further increases in reactor power. If a revised stress analysis is performed and new limit curves are developed, then TVA 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 Item (b)1 below.

(b) TVA shall implement the following actions for the initial power ascension from 3458 MWt to 3952 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 3458 MWt, TVA 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 item (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 BFN Unit 3 EPU measurements.

b. Use of scaling factors associated with all of the safety relief valve acoustic resonances as estimated in the predictive analysis or in-plant data acquired during power ascension.

2. After reaching 3952 MWt, TVA shall obtain measurements from the MSL strain gauges and establish the steam dryer flow-induced vibration load fatigue margin for the facility and update the steam dryer stress report. These data will be provided to the NRC staff as described below in item (e).

(c) TVA shall prepare the EPU PAT Plan to include the following.

1. The MSL strain gauge limit curves to be applied for evaluating steam dryer performance, based on end-to-end B&Us from BFN Unit 3 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 3458 MWt.

10. Identify the NRC Project Manager as the NRC point of contact for providing PAT plan information during power ascension.

11. Methodology for updating limit curves.

(d) The following key attributes of the PAT Plan shall not be made less restrictive without prior NRC approval:

1. During initial power ascension testing above 3458 MWt, each of the two hold points shall be at increments of approximately 5 percent of 3458 MWt.

2. Level 1 performance criteria.

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

Changes to other aspects of the PAT Plan may be made in accordance with the guidance of NEI 99-04, "Guidelines for Managing NRC Commitments," issued July 1999.

(e) Following the data collection and evaluation at the EPU power level, TVA shall provide 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 BFN Unit 3 benchmarking at EPU conditions. The report shall be submitted to NRC within 90 days of the completion of EPU power ascension testing for BFN Unit 2. Should the results of this stress analysis indicate the allowable stress in any part of the steam dryer is exceeded, TVA shall reduce power to a level at which the allowable stress is met, evaluate the steam dryer integrity, and assess any shortcomings in the predictive analysis. The results of this evaluation, including a recommended resolution of any identified issues and a demonstration of steam dryer integrity at EPU conditions, shall be provided to the NRC for review and approval prior to return to EPU conditions.

(f) Following the data collection and evaluation at the EPU power level, TVA shall provide a vibration summary report to the NRC. The summary report shall be submitted to the NRC within 90 days of the completion of EPU power ascension testing for BFN Unit 2. The vibration summary report shall include the information in items (f)1 through (f)3, as follows:

1. Vibration data for piping and valve locations deemed prone to vibration and vibration monitoring locations identified in Attachment 45 to the EPU application dated September 21, 2015, including the identified locations associated with MSLs, Feedwater Lines, Safety Relief Valves and the Main Steam Isolation Valves.

2. An evaluation of the measured vibration data collected in item (f)1 above compared against acceptance limits.

3. Vibration values and associated acceptance limits at approximately 3630 MWt, 3803 MWt, and 3952 MWt using the data collected in item (f)1, above.

(g) 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 Boiling Water Reactor Vessels and Internals Project (BWRVIP)-139A (Steam Dryer Inspection and Flaw Evaluation Guidelines) and General Electric (GE) inspection guidelines (SIL 644, BWR Steam Dryer Integrity).

(h) 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 to the NRC within 90 days following startup from each of the first two respective refueling outages.

(i) 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 items (g) and (h), 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 Item (i).

(19) Neutron Absorber Monitoring Program

The licensee shall, at least once every ten years, withdraw a neutron absorber coupon from the spent fuel pool and perform Boron-10 (B-10) areal density measurement on the coupon. Based on the results of the B-10 areal density measurement, the licensee shall perform any technical evaluations that may be necessary and take appropriate actions using relevant regulatory and licensing processes.

(20) Radiological Consequences Analyses Using Alternative Source Terms

TVA shall perform facility and licensing basis modifications to resolve the non-conforming/degraded condition associated with the Alternate Leakage Treatment pathway such that the current licensing basis dose calculations (approved in License Amendment Nos. 251/282 (Unit 1), 290/308 (Unit 2) and 249/267 (Unit 3)) would remain valid. These facility and licensing basis modifications shall be complete prior to initial power ascension above 3458 MWt.

D. The UFSAR supplement, as revised, submitted pursuant to 10 CFR 54.21(d), shall be included in the next scheduled update to the UFSAR required by 10 CFR 50.71(e)(4) following the issuance of this renewed operating license. Until that update is complete, TVA may make changes to the programs and activities described in the supplement without prior Commission approval, provided that TVA evaluates such changes pursuant to the criteria set forth in 10 CFR 50.59 and otherwise complies with the requirements in that section.

E. The UFSAR supplement, as revised, describes certain future activities to be completed prior to the period of extended operation. TVA shall complete these activities no later than June 28, 2014, and shall notify the NRC in writing when implementation of these activities is complete and can be verified by NRC inspection.

F. All capsules in the reactor vessel that are removed and tested must meet the test procedures and reporting requirements of the most recent NRC-approved version of the Boiling Water Reactor Vessels and Internals Project (BWRVIP) Integrated Surveillance Program (ISP) appropriate for the configuration of the specimens in the

1.1 Definitions (continued)

PHYSICS TESTS	PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation. These tests are: a. Described in Section 13.10, Refueling Test Program; of the FSAR; b. Authorized under the provisions of 10 CFR 50.59; or c. Otherwise approved by the Nuclear Regulatory Commission.
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of 3952 MWt.
SHUTDOWN MARGIN (SDM)	SDM shall be the amount of reactivity by which the reactor is subcritical or would be subcritical throughout the operating cycle 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 < 585 psig or core flow < 10% rated core flow:

THERMAL POWER shall be ≤ 23% RTP.

2.1.1.2 With the reactor steam dome pressure ≥ 585 psig and core flow ≥ 10% rated core flow:

MCPR shall be ≥ 1.06 for two recirculation loop operation or ≥ 1.08 for single 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.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
	Verify the concentration and temperature of boron in solution are within the limits of Figure 3.1.7-1.	Once within 8 hours after discovery that SPB concentration is > 9.2% by weight AND 12 hours thereafter
SR 3.1.7.5	Verify the minimum quantity of Boron-10 in the SLC solution tank and available for injection is ≥ 203 pounds.	31 days
SR 3.1.7.6	Verify the SLC conditions satisfy the following equation: $\frac{(C)(Q)(E)}{(8.7\ \text{wt.}\%)(50\ \text{gpm})(94\ \text{atom}\%)} \geq 1$ where, C = sodium pentaborate solution concentration (weight percent) Q = pump flow rate (gpm) E = Boron-10 enrichment (atom percent Boron-10)	31 days AND Once within 24 hours after water or boron is added to the solution
SR 3.1.7.7	Verify each pump develops a flow rate ≥ 39 gpm at a discharge pressure ≥ 1325 psig.	24 months

(continued)

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 AND 24 hours thereafter

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 24 hours thereafter
SR 3.2.2.2	Determine the MCPR limits.	Once within 72 hours after each completion of SR 3.1.4.1 AND Once within 72 hours after each completion of SR 3.1.4.2

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 24 hours thereafter

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. ----------NOTE---------- Not applicable for Functions 2.a, 2.b, 2.c, 2.d, or 2.f. ---------- One or more Functions with one or more required channels inoperable in both trip systems.	B.1 Place channel in one trip system in trip. OR B.2 Place one trip system in trip.	6 hours 6 hours
C. One or more 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% 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

(continued)

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.	24 hours
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.	7 days
SR 3.3.1.1.3	----------NOTE---------- Not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. ---------- Perform CHANNEL FUNCTIONAL TEST.	7 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.10	Perform CHANNEL CALIBRATION.	184 days
SR 3.3.1.1.11	(Deleted)	
SR 3.3.1.1.12	Perform CHANNEL FUNCTIONAL TEST.	24 months
SR 3.3.1.1.13	----------NOTE---------- Neutron detectors are excluded. ---------- Perform CHANNEL CALIBRATION.	24 months
SR 3.3.1.1.14	Perform LOGIC SYSTEM FUNCTIONAL TEST.	24 months
SR 3.3.1.1.15	Verify Turbine Stop Valve - Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure - Low Functions are not bypassed when THERMAL POWER is ≥ 26% RTP.	24 months
SR 3.3.1.1.16	----------NOTE---------- For Function 2.a, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. ---------- Perform CHANNEL FUNCTIONAL TEST.	184 days
SR 3.3.1.1.17	Verify OPRM is not bypassed when APRM Simulated Thermal Power is ≥ 23% and recirculation drive flow is < 60% of rated recirculation drive flow.	24 months

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. Intermediate Range Monitors					
a. Neutron Flux - High	2	3	G	SR 3.3.1.1.1 SR 3.3.1.1.3 SR 3.3.1.1.5 SR 3.3.1.1.6 SR 3.3.1.1.9 SR 3.3.1.1.14	≤ 120/125 divisions of full scale
	5(a)	3	H	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.9 SR 3.3.1.1.14	≤ 120/125 divisions of full scale
b. Inop	2	3	G	SR 3.3.1.1.3 SR 3.3.1.1.14	NA
	5(a)	3	H	SR 3.3.1.1.4 SR 3.3.1.1.14	NA
2. Average Power Range Monitors					
a. Neutron Flux - High, (Setdown)	2	3(b)	G	SR 3.3.1.1.1 SR 3.3.1.1.6 SR 3.3.1.1.7 SR 3.3.1.1.13 SR 3.3.1.1.16	≤ 13% RTP
b. Flow Biased Simulated Thermal Power - High	1	3(b)	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.7 SR 3.3.1.1.13 SR 3.3.1.1.16	≤ 0.55 W + 65.5% RTP and ≤ 120% RTP(c)
c. Neutron Flux - High	1	3(b)	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.7 SR 3.3.1.1.13 SR 3.3.1.1.16	≤ 120% RTP

(continued)

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

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

(c) [0.55 W + 65.5% - 0.55 Δ W] RTP when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating."

Table 3.3.1.1-1 (page 3 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
7. Scram Discharge Volume Water Level - High (continued)					
b. Float Switch	1,2	2	G	SR 3.3.1.1.8 SR 3.3.1.1.13 SR 3.3.1.1.14	≤ 46 gallons
	5(a)	2	H	SR 3.3.1.1.8 SR 3.3.1.1.13 SR 3.3.1.1.14	≤ 46 gallons
8. Turbine Stop Valve - Closure	≥ 26% RTP	4	E	SR 3.3.1.1.8 SR 3.3.1.1.13 SR 3.3.1.1.14 SR 3.3.1.1.15	≤ 10% closed
9. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low(d)	≥ 26% RTP	2	E	SR 3.3.1.1.8 SR 3.3.1.1.13 SR 3.3.1.1.14 SR 3.3.1.1.15	≥ 550 psig
10. Reactor Mode Switch - Shutdown Position	1,2	1	G	SR 3.3.1.1.12 SR 3.3.1.1.14	NA
	5(a)	1	H	SR 3.3.1.1.12 SR 3.3.1.1.14	NA
11. Manual Scram	1,2	1	G	SR 3.3.1.1.8 SR 3.3.1.1.14	NA
	5(a)	1	H	SR 3.3.1.1.8 SR 3.3.1.1.14	NA
12. RPS Channel Test Switches	1,2	2	G	SR 3.3.1.1.4	NA
	5(a)	2	H	SR 3.3.1.1.4	NA
13.Deleted					

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

(d) During instrument calibrations, if the As Found channel setpoint is conservative with respect to the Allowable Value but outside its acceptable As Found band as defined by its associated Surveillance Requirement procedure, then there shall be an initial determination to ensure confidence that the channel can perform as required before returning the channel to service in accordance with the Surveillance. If the As Found instrument channel setpoint is not conservative with respect to the Allowable Value, the channel shall be declared inoperable.

Prior to returning a channel to service, the instrument channel setpoint shall be calibrated to a value that is within the acceptable As Left tolerance of the setpoint; otherwise, the channel shall be declared inoperable.

The nominal Trip Setpoint shall be specified on design output documentation which is incorporated by reference in the Updated Final Safety Analysis Report. The methodology used to determine the nominal Trip Setpoint, the predefined As Found Tolerance, and the As Left Tolerance band, and a listing of the setpoint design output documentation shall be specified in Chapter 7 of the Updated Final Safety Analysis Report.

3.3 INSTRUMENTATION

3.3.2.2 Feedwater and Main Turbine High Water Level Trip Instrumentation

LCO 3.3.2.2 Two channels of feedwater and main turbine high water level trip instrumentation per trip system 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 feedwater and main turbine high water level trip channels inoperable, in one trip system.	A.1 Place channel(s) in trip.	7 days
B. One or more feedwater and main turbine high water level trip channels inoperable in each trip system.	B.1 Restore feedwater and main turbine high water level trip capability.	2 hours
C. Required Action and associated Completion Time not met.	C.1 Reduce THERMAL POWER to < 23% RTP.	4 hours

3.3 INSTRUMENTATION

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

LCO 3.3.4.1

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

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

APPLICABILITY: THERMAL POWER ≥ 26% RTP.

ACTIONS

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

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more channels inoperable.	A.1	Restore channel to OPERABLE status.	72 hours
	OR		
	A.2	----------NOTE---------- Not applicable if inoperable channel is the result of an inoperable breaker. --- Place channel in trip.	 72 hours
B. One or more Functions with EOC-RPT trip capability not maintained. AND MCPR and LHGR limit for inoperable EOC-RPT not made applicable.	B.1	Restore EOC-RPT trip capability.	2 hours
	OR		
	B.2	Apply the MCPR and LHGR limit for inoperable EOC-RPT as specified in the COLR.	2 hours
C. Required Action and associated Completion Time not met.	C.1	Reduce THERMAL POWER to < 26% 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 3.3.4.1.1	Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.4.1.2	Verify TSV - Closure and TCV Fast Closure, Trip Oil Pressure - Low Functions are not bypassed when THERMAL POWER is ≥ 26% RTP.	24 months
SR 3.3.4.1.3	Perform CHANNEL CALIBRATION. The Allowable Values shall be: TSV - Closure: ≤ 10% closed; and TCV Fast Closure, Trip Oil Pressure - Low: ≥ 550 psig.	24 months
SR 3.3.4.1.4	Perform LOGIC SYSTEM FUNCTIONAL TEST including breaker actuation.	24 months

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.	24 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.3.1.1	Verify ≥ 2615 gal of liquid nitrogen are contained in each nitrogen storage tank.	31 days
SR 3.6.3.1.2	Verify each CAD 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.	31 days

3.7 PLANT SYSTEMS

3.7.1 Residual Heat Removal Service Water (RHRSW) System

LCO 3.7.1

----------NOTE----------
The number of required RHRSW pumps may be reduced by one for each fueled unit that has been in MODE 4 or 5 for ≥ 24 hours.

Four RHRSW subsystems shall be OPERABLE with the number of OPERABLE pumps as listed below:

1. 1 unit fueled - four OPERABLE RHRSW pumps.

2. 2 units fueled - six OPERABLE RHRSW pumps.

3. 3 units fueled - eight OPERABLE RHRSW pumps.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required RHRSW pump inoperable.	A.1 ----------NOTES---------- 1. Only applicable for the 2 units fueled condition. 2. Only four RHRSW pumps powered from a separate 4 kV shutdown board are required to be OPERABLE if the other fueled unit has been in MODE 4 or 5 for ≥ 24 hours. ---------- Verify five RHRSW pumps powered from separate 4 kV shutdown boards are OPERABLE.	Immediately
	OR	
	A.2 Restore required RHRSW pump to OPERABLE status.	30 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One RHRSW subsystem inoperable.	B.1	----------NOTE---------- Enter applicable Conditions and Required Actions of LCO 3.4.7, "Residual Heat Removal (RHR) Shutdown Cooling - Hot Shutdown," for RHR shutdown cooling made inoperable by the RHRSW system. ----------	
		Restore RHRSW subsystem to OPERABLE status.	30 days
C. Two required RHRSW pumps inoperable.	C.1	Restore one inoperable RHRSW pump to OPERABLE status.	7 days
D. Two RHRSW subsystems inoperable.	D.1	----------NOTE---------- Enter applicable Conditions and Required Actions of LCO 3.4.7, for RHR shutdown cooling made inoperable by the RHRSW System. ----------	
		Restore one RHRSW subsystem to OPERABLE status.	7 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. Three or more required RHRSW pumps inoperable.	E.1	Restore one RHRSW pump to OPERABLE status.	8 hours
F. Three or more RHRSW subsystems inoperable.	F.1	----------NOTE---------- Enter applicable Conditions and Required Actions of LCO 3.4.7 for RHR shutdown cooling made inoperable by the RHRSW System. ----------	
		Restore one RHRSW subsystem to OPERABLE status.	8 hours
G. Required Action and associated Completion Time not met.	G.1	Be in MODE 3.	12 hours
	AND		
	G.2	Be in MODE 4.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.1.1	Verify each RHRSW 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.	31 days

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SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.2.1	Verify the average water temperature of UHS is ≤ 95°F.	24 hours
SR 3.7.2.2	----------NOTE---------- Isolation of flow to individual components does not render EECW System inoperable. ---------- Verify each EECW system manual and power operated valve in the flow paths servicing safety related systems or components, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days
SR 3.7.2.3	Verify each required EECW pump actuates on an actual or simulated initiation signal.	24 months

3.7 PLANT SYSTEMS

3.7.5 Main Turbine Bypass System

LCO 3.7.5 The Main Turbine Bypass System shall be OPERABLE.

OR

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; and

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

4.0 DESIGN FEATURES (continued)

4.3 Fuel Storage

4.3.1 Criticality

4.3.1.1 The spent fuel storage racks are designed and shall be maintained with:

a. $k_{eff} \leq 0.95$ if fully flooded with unborated water, which includes an allowance for uncertainties as described in Section 10.3 of the FSAR; and

b. Fuel assemblies having a maximum k-infinity of 0.8825 in the normal spent fuel pool storage rack configuration; and

c. A nominal 6.563 inch center to center distance between fuel assemblies placed in the storage racks.

4.3.1.2 The new fuel storage vault shall not be used for fuel storage. New fuel shall be stored in the spent fuel storage racks.

(continued)

5.5 Programs and Manuals

5.5.12 Primary Containment Leakage Rate Testing Program (continued)

The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is 49.1 psig. The maximum allowable primary containment leakage rate, L_a, shall be 2% of primary containment air weight per day at P_a.

Leakage Rate acceptance criteria are:

a. The primary containment leakage rate acceptance criteria is ≤ 1.0 L_a. During the first unit startup following the testing performed in accordance with this program, the leakage rate acceptance criteria are ≤ 0.60 L_a for the Type B and Type C tests, and ≤ 0.75 L_a for the Type A test; and

b. Air lock testing acceptance criteria are:

1) Overall air lock leakage rate ≤ 0.05 L_a when tested at $\geq P_a$.

2) Air lock door seals leakage rate is ≤ 0.02 L_a when the overall air lock is pressurized to ≥ 2.5 psig for at least 15 minutes.

The provisions of SR 3.0.2 do not apply to the test frequencies specified in the Primary Containment Leakage Rate Testing Program. The provisions of SR 3.0.3 are applicable to the Primary Containment Leakage Rate Testing Program.

5.5.13 Control Room Envelope Habitability Program

A Control Room Envelope (CRE) Habitability Program shall be established and implemented to ensure that CRE habitability is maintained such that, with an OPERABLE Control Room Emergency Ventilation (CREV) System, CRE occupants can control the reactor safely under normal conditions and maintain it in a safe condition following a radiological event, hazardous chemical release, or a smoke challenge. The program shall ensure that adequate radiation protection is provided to permit access and occupancy of the CRE under design basis accident (DBA) conditions without personnel receiving radiation exposures in excess of 5 rem total effective dose equivalent (TEDE) for the duration of the accident. The program shall include the following elements:

(continued)

5.5 Programs and Manuals

5.5.14 Residual Heat Removal (RHR) Heat Exchange Performance Monitoring Program

This program is established to ensure that the RHR heat exchangers are maintained in a condition that meets or exceeds the minimum performance capability assumed in containment analyses, which support not taking credit for containment accident pressure in the NPSH analyses. The RHR heat exchanger testing and determination of overall uncertainty in the fouling resistance shall be in accordance with the guidelines in EPRI report, EPRI 3002005340, Service Water Heat Exchanger Test Guidelines, May 2015. This program establishes the following attributes.

a. The program establishes provisions to periodically monitor RHR heat exchanger thermal performance. The program includes frequency of monitoring and the methodology considers uncertainty of the result.

b. The program establishes and controls acceptance criteria for RHR heat exchanger worst fouling resistance and number of plugged tubes.

c. The program establishes limitations and allows for compensatory actions if degraded performance is observed.

d. Changes to the program shall be made under appropriate administrative review.

e. Details of the program including program limitations, compensatory actions for degraded performance, testing method, data acquisition method, data reduction method, overall uncertainty determination method, thermal performance analysis, acceptance criteria, and computer programs used that meet the 10 CFR 50 Appendix B, and 10 CFR 21 requirements are described in the UFSAR.

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

TENNESSEE VALLEY AUTHORITY

DOCKET NO. 50-296

BROWNS FERRY NUCLEAR PLANT, UNIT 3

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 283
Renewed License No. DPR-68

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

   A. The application for amendment by the Tennessee Valley Authority (the licensee) dated September 21, 2015, as supplemented by letters dated November 13, 2015; December 15, 2015 (two letters); December 18, 2015; February 16, 2016; March 8, 2016; March 9, 2016; March 24, 2016; March 28, 2016; April 4, 2016; April 5, 2016; April 14, 2016; April 22, 2016 (two letters); April 27, 2016; May 11, 2016; May 20, 2016 (two letters); May 27, 2016; June 9, 2016; June 17, 2016; June 20, 2016; June 24, 2016; July 13, 2016 (two letters); July 27, 2016; July 29, 2016 (two letters), August 3, 2016 (three letters); September 12, 2016; September 21, 2016; September 23, 2016; October 13, 2016; October 28, 2016; October 31, 2016; January 20, 2017; February 3, 2017; March 3, 2017; and June 12, 2017, 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 Renewed Facility Operating License (RFOL) and Technical Specifications as indicated in the attachment to this license amendment. Paragraphs 2.C.(1) and 2.C.(2) of RFOL No. DPR-68 are hereby amended as follows:

   (1) Maximum Power Level

   The licensee is authorized to operate the facility at steady state reactor core power levels not in excess of 3952 megawatts thermal.

   (2) Technical Specifications

   The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 283, are hereby incorporated in the renewed operating license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. Further, RFOL No. DPR-68 is amended by changes to Item 3 under "Transition License Condition" of paragraph 2.C.(7) of the license as follows:

   3. The licensee shall complete the implementation items as listed in Table S-3, "Implementation Items," of Tennessee Valley Authority letters CNL-15-191, dated September 8, 2015, and CNL-16-165, dated October 31, 2016, within 240 days after issuance of the license amendment unless that date falls within a scheduled refueling outage, then implementation will occur within 60 days after startup from that scheduled refueling outage. Implementation items 32 and 33 are associated with modifications and will be completed after all procedure updates, modifications, and training are complete.

4. In addition, RFOL No. DPR-33 is amended by the addition of new License Conditions 2.C.(14), "Potential Adverse Flow Effects"; 2.C.(15), "Neutron Absorber Monitoring Program"; and 2.C.(16), "Radiological Consequences Analyses Using Alternative Source Terms"; as indicated in the attachment to this amendment.

5. This license amendment is effective as of its date of issuance and shall be implemented prior to startup from the refueling outage in the spring of 2018.

FOR THE NUCLEAR REGULATORY COMMISSION

Brian E. Holian, Acting Director
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Facility Operating
License and Technical Specifications

Date of Issuance: August 14, 2017

ATTACHMENT TO LICENSE AMENDMENT NO. 283

BROWNS FERRY NUCLEAR PLANT, UNIT 3

RENEWED FACILITY OPERATING LICENSE NO. DPR-68

DOCKET NO. 50-296

Replace the following pages of Renewed Facility Operating License No. DPR-68 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
5	5
6	6
--	6a
--	6b
--	6c
--	6d
--	6e
--	6f

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

REMOVE	INSERT
1.1-6	1.1-6
2.0-1	2.0-1
3.1-25	3.1-25
3.2-1	3.2-1
3.2-2	3.2-2
3.2-3	3.2-3
3.2-4	3.2-4
3.2-5	3.2-5
3.2-6	3.2-6
3.3-2	3.3-2
3.3-4	3.3-4
3.3-6	3.3-6
3.3-7	3.3-7
3.3-9	3.3-9
3.3-22	3.3-22
3.3-30	3.3-30
3.3-31	3.3-31
3.3-32	3.3-32
3.4-6	3.4-6

REMOVE	INSERT
3.6-41	3.6-41
3.7-1	3.7-1
3.7-2	3.7-2
3.7-3	3.7-3
3.7-4	3.7-4
3.7-5	3.7-5
3.7-6	3.7-6
3.7-8	3.7-8
3.7-17	3.7-17
4.0-2	4.0-2
5.0-21	5.0-21
---	5.0-21b

(3) Pursuant to the Act and 10 CFR Parts 30, 40, and 70, to receive, possess, and use at any time any byproduct, source, and special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(4) Pursuant to the Act and 10 CFR Parts 30, 40, and 70, to receive, possess, and use in amounts as required any byproduct, source, or special nuclear material without restriction to chemical or physical form for sample analysis or equipment and instrument calibration or associated with radioactive apparatus or components;

(5) Pursuant to the Act and 10 CFR Parts 30 and 70, to possess but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. This renewed operating 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, Sections 50.54 and 50.59 of Part 50, and Section 70.32 of Part 70; is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

The licensee is authorized to operate the facility at steady state reactor core power levels not in excess of 3952 megawatts thermal.

(2) Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 283, are hereby incorporated in the renewed operating license. The licensee shall operate the facility in accordance with the Technical Specifications.

For Surveillance Requirements (SRs) that are new in Amendment 212 to Facility Operating License DPR-68, the first performance is due at the end of the first surveillance interval that begins at implementation of the Amendment 212. For SRs that existed prior to Amendment 212, including SRs with modified acceptance criteria and SRs whose frequency of performance is being extended, the first performance is due at the end of the first surveillance interval that begins on the date the surveillance was last performed prior to implementation of Amendment 212.

3. The licensee shall complete the implementation items as listed in Table S-3, "Implementation Items," of Tennessee Valley Authority letters CNL-15-191, dated September 8, 2015; and CNL-16-165, dated October 31, 2016; within 240 days after issuance of the license amendment unless that date falls within a scheduled refueling outage, then implementation will occur within 60 days after startup from that scheduled refueling outage. Implementation items 32 and 33 are associated with modifications and will be completed after all procedure updates, modifications, and training are complete.

(8) Deleted.

(9) The licensee shall maintain the Augmented Quality Program for the Standby Liquid Control System to provide quality control elements to ensure component reliability for the required alternative source term function defined in the Updated Final Safety Analyses Report (UFSAR).

(10) Mitigation Strategy License Condition

Develop and maintain strategies for addressing large fires and explosions and that include the following key areas:

(a) Fire fighting response strategy with the following elements:
   1. Pre-defined coordinated fire response strategy and guidance
   2. Assessment of mutual aid fire fighting assets
   3. Designated staging areas for equipment and materials
   4. Command and control
   5. Training of response personnel

(b) Operations to mitigate fuel damage considering the following:
   1. Protection and use of personnel assets
   2. Communications
   3. Minimizing fire spread
   4. Procedures for implementing integrated fire response strategy
   5. Identification of readily-available pre-staged equipment
   6. Training on integrated fire response strategy
   7. Spent fuel pool mitigation measures

(c) Actions to minimize release to include consideration of:
   1. Water spray scrubbing
   2. Dose to onsite responders

(11) The licensee shall implement and maintain all Actions required by Attachment 2 to NRC Order EA-06-137, issued June 20, 2006, except the last action that requires incorporation of the strategies into the site security plan, contingency plan, emergency plan and/or guard training and qualification plan, as appropriate.

(12) Upon completion of Amendment No. 261, adopting TSTF-448, Revision 3, the determination of control room envelope (CRE) unfiltered air inleakage as required by SR 3.7.3.4, in accordance with TS 5.5.13.c(i), the assessment of the CRE habitability as required by TS 5.5.13.c(ii), and the measurement of the CRE pressure as required by TS 5.5.13.d, shall be considered met.

(3) Following Implementation:

(a) The first performance of SR 3.7.4.4, in accordance with TS 5.5.13.c.(i), shall be within a specific frequency of 6 years, plus the 18-month allowance of SR 3.0.2, as measured from November 10, 2003, the date of the most recent successful tracer gas test.

(b) The first performance of the periodic assessment of the Control Room Envelope (CRE) Habitability, Technical Specification 5.5.13.c.(ii), shall be within 9 months following the initial implementation of the TS Change. The next performance of the periodic assessment will be in a period specified by the CRE Program. That is 3 years from the last successful performance of the Technical Specification 5.5.13.c.(ii) tracer gas test.

(c) The first performance of the periodic measurement of CRE pressure, TS 5.5.13.d, shall be within 24 months, plus 180 days allowed by SR 3.0.2 as measured from the date of the most recent successful pressure measurement test.

(d) For License Amendment 268 ,the licensee shall implement changes to BFN, Unit 3 TSs 5.6.5 and 3.3.1.1 within 60 days of approval. The remaining BFN, Unit 3, changes will be implemented upon completion of required supporting modification work and prior to entering Mode 3 (i.e., Hot Shutdown) from the spring 2014 refueling outage.

(13) The fuel channel bow standard deviation component of the channel bow model uncertainty used by ANP-10307PA, "AREVA MCPR Safety Limit Methodology for Boiling Water Reactors, Revision 0," (i.e., TS 5.6.5.b.11) to determine the Safety Limit Minimum Critical Power Ratio shall be increased by the ratio of channel fluence gradient to the nearest channel fluence gradient bound of the channel measurement database, when applied to channels with fluence gradients outside the bounds of the measurement database from which the model uncertainty is determined. This license condition will be effective upon the implementation of Amendment No. 270.

(14) Potential Adverse Flow Effects

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) for initial power ascension from 3458 MWt to the extended uprate (EPU) level of 3952 MWt.

(a) The following requirements are placed on operation of the facility before and during the initial power ascension to 3458 MWt:

1. TVA shall provide a Power Ascension Test (PAT) Plan for the BFN Unit 3 steam dryer testing. This plan shall include:

   a. Criteria for comparison and evaluation of projected strain and acceleration with on-dryer instrument data.

   b. Acceptance limits developed for each on-dryer strain gauge.

   c. Tables of predicted dryer stresses at a power level of 3458 MWt, strain amplitudes and power spectral densities at strain gauge locations, and maximum stresses and locations.

   The PAT plan shall provide correlations between measured strains and the corresponding maximum stresses. The PAT plan shall be submitted to the NRC Project Manager no later than 10 days before start-up.

2. TVA shall monitor the main steamline (MSL) strain gauges and on-dryer instrumentation at a minimum of three power levels up to 3458 MWt. Based on a comparison of projected and measured strains and accelerations, BFN will assess whether the dryer acoustic and structural models have adequately captured the response significant to peak stress projections. If the measured strains and accelerations are not within the 3458 MWt acceptance limits, the new measured data will be used to re-perform the full structural re-analysis for the purposes of generating modified EPU acceptance limits.

   a. If the on-dryer instrumentation is unavailable, the BFN Unit 3 power ascension will be monitored using the available MSL strain gauges. The predicted dryer loads during the power ascension will be calculated with the Plant Based Load Evaluation (PBLE) Method 2 transfer function used in the steam dryer design analyses for EPU. The acceptance limits will ensure that the steam dryer stress margins remain above the final minimum alternating stress ratio (MASR) accepted in the EPU design analyses.

3. BFN shall provide a summary of the data and evaluation of predicted and measured pressures, strains, and accelerations at a power level of 3458 MWt. These data will include the BFN-specific bias and uncertainty data and transfer function, revised peak stress table and any revised acceptance limits. The predicted pressures shall include those using both PBLE methods (that is, Method 1 using on-dryer data, and Method 2 using MSL data). It shall be provided to the NRC Project Manager upon completion of the evaluation. TVA shall not increase power above 3458 MWt until the NRC Project Manager notifies TVA that NRC accepts the evaluation or NRC questions regarding the

evaluation have been addressed. If no questions are identified within 240 hours after the NRC receives the evaluation, power ascension may continue.

a. If the on-dryer instrumentation is unavailable and the BFN-specific bias and uncertainty data and transfer function cannot be developed when BFN Unit 3 reaches a power level of 3458 MWt, the BFN Unit 3 power ascension above 3458 MWt will be monitored using the available MSL strain gauges. The predicted dryer loads during the power ascension will be calculated with the PBLE Method 2 transfer function used in the steam dryer design analyses for EPU. The acceptance limits will ensure that the steam dryer stress margins remain above the final MASR accepted in the EPU design analyses.

(b) The following requirements are placed on operation of the facility during the initial power ascension from 3458 MWt to the approved EPU level (3952 MWt):

1. At test increments that do not exceed 2.5 percent of 3458 MWt (approximately 86 MWt), TVA shall hold the facility at approximately steady state conditions and collect data from available MSL strain gauges and available on-dryer instrumentation. This data will be evaluated, including the comparison of measured dryer strains to acceptance limits and the comparison of predicted dryer loads based on MSL strain gauge data to acceptance limits. It will also be used to trend and project loads at the next test point and to EPU conditions to demonstrate margin for continued power ascension.

   a. If the on-dryer instrumentation becomes unavailable during power ascension above 3458 MWt, the BFN Unit 3 power ascension above 3458 MWt will be monitored using the available MSL strain gauges. The predicted dryer loads during the power ascension will be calculated with the BFN-specific PBLE Method 2 transfer function developed from the on-dryer instrumentation and MSL strain gauge data taken at the 3458 MWt hold point, the BFN-specific bias and uncertainty data, the revised peak stresses, and revised acceptance criteria developed in item (a)3 above. The acceptance limits will maintain the steam dryer stress margins above a MASR of 1.0.

2. Following the data collection and evaluation at the plateaus at approximately 3630 MWt, 3803 MWt, and 3952 MWt, TVA shall provide a summary of the data and the evaluation performed in item (b)1 above to the NRC Project Manager. TVA shall not increase power above these power levels for up to 96 hours after the NRC Project Manager confirms receipt of the summary, unless prior to expiration of the 96 hour period, the NRC Project Manager advises that the NRC staff has no objection to continuation of power ascension.

3. Should the measured strains on the dryer exceed the Level 1 acceptance limits, or alternatively if the dryer instrumentation is not available and the projected load on the dryer from the MSL strain gauge data exceeds the Level 1 acceptance limits, TVA shall return the facility to a power level at which the limits are not exceeded. TVA shall resolve the discrepancy, evaluate and document the continued structural integrity of the steam dryer, and provide that documentation to the NRC Project Manager prior to further increases in reactor power. TVA shall not increase power for up to 96 hours to allow for NRC review and approval of the information.

   a. In the event that acoustic signals (in MSL strain gauge signals) are identified that challenge the dryer acceptance limits during power ascension above 3458 MWt, TVA shall evaluate dryer loads, and stresses, including the effect of ±10 percent frequency shift, and re-establish the acceptance limits and determine whether there is margin for continued power ascension.

   b. During power ascension above 3458 MWt, if an engineering evaluation for the steam dryer is required because a Level 1 acceptance limit is exceeded, TVA shall perform the structural analysis using the Steam Dryer Report, Appendix A methods to address frequency uncertainties up to ±10 percent and assure that peak responses that fall within this uncertainty band are addressed.

4. a. Following the data collection and evaluation at the EPU power level, TVA shall provide a final load definition and stress report of the steam dryer, including the results of a complete re-analysis using the BFN-specific bias and uncertainties and transfer function, to the NRC. The BFN-specific bias and uncertainties summary shall include both PBLE Method 1 and Method 2. This report shall be submitted to the NRC within 90 days of the completion of EPU power ascension testing for BFN Unit 3. Should the results of this stress analysis indicate the allowable stress in any part of the dryer is exceeded, TVA shall reduce power to a level at which the allowable stress is met, evaluate the dryer integrity, and assess any shortcomings in the predictive analysis. The results of this evaluation, including a recommended resolution of any identified issues and a demonstration of dryer integrity at EPU conditions, shall be provided to the NRC for review and approval prior to return to EPU conditions.

   b. Within 30 days after completion of the core flow sweep test at EPU conditions to determine any compounding effect due to alignment of Vane Passing Frequency and Safety Relief Valve resonance frequencies, TVA shall provide the core flow sweep test results for NRC review.

5. Following the data collection and evaluation at the EPU power level, TVA shall provide a vibration summary report to the NRC. The summary report shall be submitted to the NRC within 90 days of the completion of EPU power ascension testing for BFN Unit 3. The vibration summary report shall include the information in items 5.a through 5.c, as follows:

   a. Vibration data for piping and valve locations deemed prone to vibration and vibration monitoring locations identified in Attachment 45 to the EPU application dated September 21, 2015, including the identified locations associated with MSLs, Feedwater Lines, Safety Relief Valves and the Main Steam Isolation Valves.

   b. An evaluation of the measured vibration data collected in item 5.a above compared against acceptance limits.

   c. Vibration values and associated acceptance limits at approximately 3630 MWt, 3803 MWt, and 3952 MWt using the data collected in item 5.a, above.

(c) TVA shall prepare the EPU PAT plan to include the following.

1. Level 1 and Level 2 acceptance limits for on-dryer strain gauges and for projected dryer loads from MSL strain gauge data to be used up to 3952 MWt.

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

3. Activities to be accomplished during 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 TVA application and all supplements to the application in support of the EPU LAR pertaining to the steam dryer before power increase above 3458 MWt.

10. Identify the NRC Project Manager as the NRC point of contact for providing PAT plan information during power ascension.

11. Methodology for updating limit curves.

(d) The following key attributes of the PAT Plan shall not be made less restrictive without prior NRC approval.

1. During initial power ascension testing above 3458 MWt, each of the two hold points shall be at increments of approximately 5 percent of 3458 MWt.

2. Level 1 performance criteria.

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

Changes to other aspects of the PAT Plan may be made in accordance with the guidance of NEI 99-04, "Guidelines for Managing NRC Commitments," issued July 1999.

(e) During the first two scheduled refueling outages after reaching full EPU conditions, TVA shall conduct a visual inspection of all accessible, susceptible locations of the steam dryer in accordance with Boiling Water Reactor Vessels and Internals Project (BWRVIP)-139A (Steam Dryer Inspection and Flaw Evaluation Guidelines) and General Electric) GE inspection guidelines (SIL 644, BWR Steam Dryer Integrity).

(f) 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 to NRC within 90 days following startup from each of the first two respective refueling outages.

(g) 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.

This license condition described above shall expire: (1) upon satisfaction of the requirements in items (e) and (f) provided that a visual inspection of the steam dryer does not reveal any new unacceptable flaw(s) or unacceptable flaw growth that is caused by fatigue, and; (2) upon satisfaction of the requirements specified in item (g).

(15) Neutron Absorber Monitoring Program

The licensee shall, at least once every ten years, withdraw a neutron absorber coupon from the spent fuel pool and perform Boron-10 (B-10) areal density measurement on the coupon. Based on the results of the B-10 areal density measurement, the licensee shall perform any technical evaluations that may be necessary and take appropriate actions using relevant regulatory and licensing processes.

(16) Radiological Consequences Analyses Using Alternative Source Terms

TVA shall perform facility and licensing basis modifications to resolve the non-conforming/degraded condition associated with the Alternate Leakage Treatment pathway such that the current licensing basis dose calculations (approved in License Amendment Nos. 251/282 (Unit 1), 290/308 (Unit 2) and 249/267 (Unit 3)) would remain valid. These facility and licensing basis modifications shall be complete prior to initial power ascension above 3458 MWt.

D. The UFSAR supplement, as revised, submitted pursuant to 10 CFR 54.21(d), shall be included in the next scheduled update to the UFSAR required by 10 CFR 50.71(e)(4) following the issuance of this renewed operating license. Until that update is complete, TVA may make changes to the programs and activities described in the supplement without prior Commission approval, provided that TVA evaluates such changes pursuant to the criteria set forth in 10 CFR 50.59 and otherwise complies with the requirements in that section.

E. The UFSAR supplement, as revised, describes certain future activities to be completed prior to the period of extended operation. TVA shall complete these activities no later than July 2, 2016, and shall notify the NRC in writing when implementation of these activities is complete and can be verified by NRC inspection.

1.1 Definitions (continued)

PHYSICS TESTS	PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation. These tests are: a. Described in Section 13.10, Refueling Test Program; of the FSAR; b. Authorized under the provisions of 10 CFR 50.59; or c. Otherwise approved by the Nuclear Regulatory Commission.
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of 3952 MWt.
SHUTDOWN MARGIN (SDM)	SDM shall be the amount of reactivity by which the reactor is subcritical or would be subcritical throughout the operating cycle 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 < 585 psig or core flow < 10% rated core flow:

THERMAL POWER shall be ≤ 23% RTP.

2.1.1.2 With the reactor steam dome pressure ≥ 585 psig and core flow ≥ 10% rated core flow:

MCPR shall be ≥ 1.06 for two recirculation loop operation or ≥ 1.08 for single 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.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
	Verify the concentration and temperature of boron in solution are within the limits of Figure 3.1.7-1.	Once within 8 hours after discovery that SPB concentration is > 9.2% by weight AND 12 hours thereafter
SR 3.1.7.5	Verify the minimum quantity of Boron-10 in the SLC solution tank and available for injection is ≥ 203 pounds.	31 days
SR 3.1.7.6	Verify the SLC conditions satisfy the following equation: $\frac{(C)(Q)(E)}{(8.7\ \text{wt.}\%)(50\ \text{gpm})(94\ \text{atom}\%)} \geq 1$ where, C = sodium pentaborate solution concentration (weight percent) Q = pump flow rate (gpm) E = Boron-10 enrichment (atom percent Boron-10)	31 days AND Once within 24 hours after water or boron is added to the solution
SR 3.1.7.7	Verify each pump develops a flow rate ≥ 39 gpm at a discharge pressure ≥ 1325 psig.	24 months

(continued)

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 AND 24 hours thereafter

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 24 hours thereafter
SR 3.2.2.2	Determine the MCPR limits.	Once within 72 hours after each completion of SR 3.1.4.1 AND Once within 72 hours after each completion of SR 3.1.4.2

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 24 hours thereafter

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. ----------NOTE---------- Not applicable for Functions 2.a, 2.b, 2.c, 2.d, or 2.f. ---------- One or more Functions with one or more required channels inoperable in both trip systems.	B.1	Place channel in one trip system in trip.	6 hours
	OR		
	B.2	Place one trip system in trip.	6 hours
C. One or more 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% 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

(continued)

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.	24 hours
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.	7 days
SR 3.3.1.1.3	----------NOTE---------- Not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. ---------- Perform CHANNEL FUNCTIONAL TEST.	7 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.10	Perform CHANNEL CALIBRATION.	184 days
SR 3.3.1.1.11	(Deleted)	
SR 3.3.1.1.12	Perform CHANNEL FUNCTIONAL TEST.	24 months
SR 3.3.1.1.13	----------NOTE---------- Neutron detectors are excluded. ---------- Perform CHANNEL CALIBRATION.	 24 months
SR 3.3.1.1.14	Perform LOGIC SYSTEM FUNCTIONAL TEST.	24 months
SR 3.3.1.1.15	Verify Turbine Stop Valve - Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure - Low Functions are not bypassed when THERMAL POWER is ≥ 26% RTP.	24 months
SR 3.3.1.1.16	----------NOTE---------- For Function 2.a, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. ---------- Perform CHANNEL FUNCTIONAL TEST.	 184 days
SR 3.3.1.1.17	Verify OPRM is not bypassed when APRM Simulated Thermal Power is ≥ 23% and recirculation drive flow is < 60% of rated recirculation drive flow.	24 months

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. Intermediate Range Monitors					
a. Neutron Flux - High	2	3	G	SR 3.3.1.1.1 SR 3.3.1.1.3 SR 3.3.1.1.5 SR 3.3.1.1.6 SR 3.3.1.1.9 SR 3.3.1.1.14	≤ 120/125 divisions of full scale
	5(a)	3	H	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.9 SR 3.3.1.1.14	≤ 120/125 divisions of full scale
b. Inop	2	3	G	SR 3.3.1.1.3 SR 3.3.1.1.14	NA
	5(a)	3	H	SR 3.3.1.1.4 SR 3.3.1.1.14	NA
2. Average Power Range Monitors					
a. Neutron Flux - High, (Setdown)	2	3(b)	G	SR 3.3.1.1.1 SR 3.3.1.1.6 SR 3.3.1.1.7 SR 3.3.1.1.13 SR 3.3.1.1.16	≤ 13% RTP
b. Flow Biased Simulated Thermal Power - High	1	3(b)	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.7 SR 3.3.1.1.13 SR 3.3.1.1.16	≤ 0.55 W + 65.5% RTP and ≤ 120% RTP(c)
c. Neutron Flux - High	1	3(b)	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.7 SR 3.3.1.1.13 SR 3.3.1.1.16	≤ 120% RTP

(continued)

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

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

(c) [0.55 W + 65.5% - 0.55 Δ W] RTP when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating."

Table 3.3.1.1-1 (page 3 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
7. Scram Discharge Volume Water Level - High					
b. Float Switch	1,2	2	G	SR 3.3.1.1.8 SR 3.3.1.1.13 SR 3.3.1.1.14	≤ 46 gallons
	5(a)	2	H	SR 3.3.1.1.8 SR 3.3.1.1.13 SR 3.3.1.1.14	≤ 46 gallons
8. Turbine Stop Valve - Closure	≥ 26% RTP	4	E	SR 3.3.1.1.8 SR 3.3.1.1.13 SR 3.3.1.1.14 SR 3.3.1.1.15	≤ 10% closed
9. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low(d)	≥ 26% RTP	2	E	SR 3.3.1.1.8 SR 3.3.1.1.13 SR 3.3.1.1.14 SR 3.3.1.1.15	≥ 550 psig
10. Reactor Mode Switch - Shutdown Position	1,2	1	G	SR 3.3.1.1.12 SR 3.3.1.1.14	NA
	5(a)	1	H	SR 3.3.1.1.12 SR 3.3.1.1.14	NA
11. Manual Scram	1,2	1	G	SR 3.3.1.1.8 SR 3.3.1.1.14	NA
	5(a)	1	H	SR 3.3.1.1.8 SR 3.3.1.1.14	NA
12. RPS Channel Test Switches	1,2	2	G	SR 3.3.1.1.4	NA
	5(a)	2	H	SR 3.3.1.1.4	NA
13. Deleted					

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

(d) During instrument calibrations, if the As Found channel setpoint is conservative with respect to the Allowable Value but outside its acceptable As Found band as defined by its associated Surveillance Requirement procedure, then there shall be an initial determination to ensure confidence that the channel can perform as required before returning the channel to service in accordance with the Surveillance. If the As Found instrument channel setpoint is not conservative with respect to the Allowable Value, the channel shall be declared inoperable.

Prior to returning a channel to service, the instrument channel setpoint shall be calibrated to a value that is within the acceptable As Left tolerance of the setpoint; otherwise, the channel shall be declared inoperable.

The nominal Trip Setpoint shall be specified on design output documentation which is incorporated by reference in the Updated Final Safety Analysis Report. The methodology used to determine the nominal Trip Setpoint, the predefined As Found Tolerance, and the As Left Tolerance band, and a listing of the setpoint design output documentation shall be specified in Chapter 7 of the Updated Final Safety Analysis Report.

3.3 INSTRUMENTATION

3.3.2.2 Feedwater and Main Turbine High Water Level Trip Instrumentation

LCO 3.3.2.2 Two channels of feedwater and main turbine high water level trip instrumentation per trip system 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 feedwater and main turbine high water level trip channels inoperable, in one trip system.	A.1 Place channel(s) in trip.	7 days
B. One or more feedwater and main turbine high water level trip channels inoperable in each trip system.	B.1 Restore feedwater and main turbine high water level trip capability.	2 hours
C. Required Action and associated Completion Time not met.	C.1 Reduce THERMAL POWER to < 23% RTP.	4 hours

3.3 INSTRUMENTATION

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

LCO 3.3.4.1

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

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

APPLICABILITY: THERMAL POWER ≥ 26% RTP.

ACTIONS

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

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more channels inoperable.	A.1	Restore channel to OPERABLE status.	72 hours
	OR		
	A.2	----------NOTE---------- Not applicable if inoperable channel is the result of an inoperable breaker. ----------	
		Place channel in trip.	72 hours
B. One or more Functions with EOC-RPT trip capability not maintained.	B.1	Restore EOC-RPT trip capability.	2 hours
	OR		
AND	B.2	Apply the MCPR and LHGR limit for inoperable EOC-RPT as specified in the COLR.	2 hours
MCPR and LHGR limit for inoperable EOC-RPT not made applicable.			
C. Required Action and associated Completion Time not met.	C.1	Reduce THERMAL POWER to < 26% 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 3.3.4.1.1	Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.4.1.2	Verify TSV - Closure and TCV Fast Closure, Trip Oil Pressure - Low Functions are not bypassed when THERMAL POWER is ≥ 26% RTP.	24 months
SR 3.3.4.1.3	Perform CHANNEL CALIBRATION. The Allowable Values shall be: TSV - Closure: ≤ 10% closed; and TCV Fast Closure, Trip Oil Pressure - Low: ≥ 550 psig.	24 months
SR 3.3.4.1.4	Perform LOGIC SYSTEM FUNCTIONAL TEST including breaker actuation.	24 months

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.	24 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.3.1.1	Verify ≥ 2615 gal of liquid nitrogen are contained in each nitrogen storage tank.	31 days
SR 3.6.3.1.2	Verify each CAD 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.	31 days

3.7 PLANT SYSTEMS

3.7.1 Residual Heat Removal Service Water (RHRSW) System

LCO 3.7.1

----------NOTE----------
The number of required RHRSW pumps may be reduced by one for each fueled unit that has been in MODE 4 or 5 for ≥ 24 hours.

Four RHRSW subsystems shall be OPERABLE with the number of OPERABLE pumps as listed below:

1. 1 unit fueled - four OPERABLE RHRSW pumps.
2. 2 units fueled - six OPERABLE RHRSW pumps.
3. 3 units fueled - eight OPERABLE RHRSW pumps.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required RHRSW pump inoperable.	A.1 ----------NOTES---------- 1. Only applicable for the 2 units fueled condition. 2. Only four RHRSW pumps powered from a separate 4 kV shutdown board are required to be OPERABLE if the other fueled unit has been in MODE 4 or 5 for ≥ 24 hours. ---------- Verify five RHRSW pumps powered from separate 4 kV shutdown boards are OPERABLE.	Immediately
	OR	
	A.2 Restore required RHRSW pump to OPERABLE status.	30 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One RHRSW subsystem inoperable.	B.1	----------NOTE---------- Enter applicable Conditions and Required Actions of LCO 3.4.7, "Residual Heat Removal (RHR) Shutdown Cooling - Hot Shutdown," for RHR shutdown cooling made inoperable by the RHRSW system. ----------	
		Restore RHRSW subsystem to OPERABLE status.	30 days
C. Two required RHRSW pumps inoperable.	C.1	Restore one inoperable RHRSW pump to OPERABLE status.	7 days
D. Two RHRSW subsystems inoperable.	D.1	----------NOTE---------- Enter applicable Conditions and Required Actions of LCO 3.4.7, for RHR shutdown cooling made inoperable by the RHRSW System. ----------	
		Restore one RHRSW subsystem to OPERABLE status.	7 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. Three or more required RHRSW pumps inoperable.	E.1	Restore one RHRSW pump to OPERABLE status.	8 hours
F. Three or more RHRSW subsystems inoperable.	F.1	----------NOTE---------- Enter applicable Conditions and Required Actions of LCO 3.4.7 for RHR shutdown cooling made inoperable by the RHRSW System. ----------	
		Restore one RHRSW subsystem to OPERABLE status.	8 hours
G. Required Action and associated Completion Time not met.	G.1	Be in MODE 3.	12 hours
	AND		
	G.2	Be in MODE 4.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.1.1	Verify each RHRSW 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.	31 days

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SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.2.1	Verify the average water temperature of UHS is ≤ 95°F.	24 hours
SR 3.7.2.2	----------NOTE---------- Isolation of flow to individual components does not render EECW System inoperable. ---------- Verify each EECW system manual and power operated valve in the flow paths servicing safety related systems or components, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days
SR 3.7.2.3	Verify each required EECW pump actuates on an actual or simulated initiation signal.	24 months

3.7 PLANT SYSTEMS

3.7.5 Main Turbine Bypass System

LCO 3.7.5 The Main Turbine Bypass System shall be OPERABLE.

OR

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; and

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

4.0 DESIGN FEATURES (continued)

4.3 Fuel Storage

4.3.1 Criticality

4.3.1.1 The spent fuel storage racks are designed and shall be maintained with:

a. $k_{eff} \leq 0.95$ if fully flooded with unborated water, which includes an allowance for uncertainties as described in Section 10.3 of the FSAR; and

b. Fuel assemblies having a maximum k-infinity of 0.8825 in the normal spent fuel pool storage rack configuration; and

c. A nominal 6.563 inch center to center distance between fuel assemblies placed in the storage racks.

4.3.1.2 The new fuel storage vault shall not be used for fuel storage. New fuel shall be stored in the spent fuel storage racks.

(continued)

5.5 Programs and Manuals

5.5.12 Primary Containment Leakage Rate Testing Program (continued)

The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is 49.1 psig. The maximum allowable primary containment leakage rate, L_a, shall be 2% of primary containment air weight per day at P_a.

Leakage Rate acceptance criteria are:

a. The primary containment leakage rate acceptance criteria is ≤ 1.0 L_a. During the first unit startup following the testing performed in accordance with this program, the leakage rate acceptance criteria are ≤ 0.60 L_a for the Type B and Type C tests, and ≤ 0.75 L_a for the Type A test; and

b. Air lock testing acceptance criteria are:

1) Overall air lock leakage rate ≤ 0.05 L_a when tested at $\geq P_a$.

2) Air lock door seals leakage rate is ≤ 0.02 L_a when the overall air lock is pressurized to ≥ 2.5 psig for at least 15 minutes.

The provisions of SR 3.0.2 do not apply to the test frequencies specified in the Primary Containment Leakage Rate Testing Program. The provisions of SR 3.0.3 are applicable to the Primary Containment Leakage Rate Testing Program.

5.5.13 Control Room Envelope Habitability Program

A Control Room Envelope (CRE) Habitability Program shall be established and implemented to ensure that CRE habitability is maintained such that, with an OPERABLE Control Room Emergency Ventilation (CREV) System, CRE occupants can control the reactor safely under normal conditions and maintain it in a safe condition following a radiological event, hazardous chemical release, or a smoke challenge. The program shall ensure that adequate radiation protection is provided to permit access and occupancy of the CRE under design basis accident (DBA) conditions without personnel receiving radiation exposures in excess of 5 rem total effective dose equivalent (TEDE) for the duration of the accident. The program shall include the following elements:

5.5 Programs and Manuals

5.5.14 Residual Heat Removal (RHR) Heat Exchanger Performance Monitoring Program

This program is established to ensure that the RHR heat exchangers are maintained in a condition that meets or exceeds the minimum performance capability assumed in containment analyses, which support not taking credit for containment accident pressure in the NPSH analyses. The RHR heat exchanger testing and determination of overall uncertainty in the fouling resistance shall be in accordance with the guidelines in EPRI report, EPRI 3002005340, Service Water Heat Exchanger Test Guidelines, May 2015. This program establishes the following attributes.

a. The program establishes provisions to periodically monitor RHR heat exchanger thermal performance. The program includes frequency of monitoring and the methodology considers uncertainty of the result.

b. The program establishes and controls acceptance criteria for RHR heat exchanger worst fouling resistance and number of plugged tubes.

c. The program establishes limitations and allows for compensatory actions if degraded performance is observed.

d. Changes to the program shall be made under appropriate administrative review.

e. Details of the program including program limitations, compensatory actions for degraded performance, testing method, data acquisition method, data reduction method, overall uncertainty determination method, thermal performance analysis, acceptance criteria, and computer programs used that meet the 10 CFR 50 Appendix B, and 10 CFR 21 requirements are described in the UFSAR.

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

SAFETY EVALUATION BY

THE OFFICE OF NUCLEAR REACTOR REGULATION

REGARDING EXTENDED POWER UPRATE

RELATED TO AMENDMENT NOS. 299, 323, AND 283

TO RENEWED FACILITY OPERATING LICENSE NOS. DPR-33, DPR-52, AND DPR-68

TENNESSEE VALLEY AUTHORITY

BROWNS FERRY NUCLEAR PLANT, UNITS 1, 2, AND 3

DOCKET NOS. 50-259, 50-260, AND 50-296

This document contains proprietary information pursuant to Title 10 of *Code of Federal Regulations* (10 CFR), Section 2.390. Proprietary information is identified by bold text enclosed within double brackets, as shown here **[[example proprietary text]]**.

Enclosure 5

BROWNS FERRY NUCLEAR PLANT, UNITS 1, 2, AND 3
SAFETY EVALUATION FOR EXTENDED POWER UPRATE

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1.0 INTRODUCTION

1.1 Application

By application dated September 21, 2015 (Reference 1), as supplemented by letters dated November 13, 2015 (Reference 2); December 15, 2015 (2 letters) (Reference 3) and (Reference 4); December 18, 2015 (Reference 5); February 16, 2016 (Reference 6); March 8, 2016 (Reference 7); March 9, 2016 (Reference 8); March 24, 2016 (Reference 9); March 28, 2016 (Reference 10); April 4, 2016 (Reference 11); April 5, 2016 (Reference 12); April 14, 2016 (Reference 13); April 22, 2016 (2 letters) (Reference 14) and (Reference 15); April 27, 2016 (Reference 16); May 11, 2016 (Reference 17); May 20, 2016 (2 letters) (Reference 18) and (Reference 19); May 27, 2016 (Reference 20); June 9, 2016 (Reference 21); June 17, 2016 (Reference 22), June 20, 2016 (Reference 23); June 24, 2016 (Reference 24); July 13, 2016 (2 letters) (Reference 25) and (Reference 26); July 27, 2016 (Reference 27); July 29, 2016 (2 letters) (Reference 28) and (Reference 29); August 3, 2016 (3 letters) (Reference 30), (Reference 31), and (Reference 32); September 12, 2016 (Reference 33); September 21, 2016 (Reference 34); September 23, 2016 (Reference 35); October 13, 2016 (Reference 36); October 28, 2016 (Reference 37), October 31, 2016 (Reference 38); January 20, 2017 (Reference 39); February 3, 2017 (Reference 40); March 3, 2017 (Reference 41); and June 12, 2017 (Reference 42) Tennessee Valley Authority (TVA, the licensee) requested changes the Technical Specifications (TSs) and to Facility Operating License Nos. DPR-33, DPR-52, and DPR-68 for Browns Ferry Nuclear Plant (BFN), Units 1, 2, and 3 (Browns Ferry), respectively.

The proposed changes would increase the maximum steady-state reactor core power level for each of the three units from 3458 megawatts thermal (MWt) to 3952 MWt. This represents an increase of approximately 20 percent above the original licensed thermal power (OLTP) level of 3293 MWt, and an increase of approximately 14.3 percent above the current licensed thermal power (CLTP) level of 3458 MWt. The proposed increase in power level is considered an extended power uprate (EPU).

Portions of the letters dated September 21, 2015; November 13, 2015; December 15, 2015 (2 letters); December 18, 2015; February 16, 2016; March 24, 2016; April 4, 2016; May 20, 2016; May 27, 2016; June 9, 2016; June 17, 2016; July 13, 2016; July 27, 2016; July 29, 2016; August 3, 2016 (2); September 21, 2016; September 23, 2016; October 13, 2016; October 28, 2016; and January 20, 2017; contain sensitive unclassified non-safeguards information and, accordingly, have been withheld from public disclosure.

The supplemental letters dated April 22, 2016; April 27, 2016; May 5, 2016; May 11, 2016; May 20, 2016 (2 letters); May 27, 2016; June 9, 2016; June 17, 2016; June 20, 2016; June 24, 2016; July 13, 2016 (2 letters); July 27, 2016; July 29, 2016 (2 letters); August 3, 2016 (3 letters); September 12, 2016; September 21, 2016; September 23; 2016; October 13, 2016, October 28, 2016; October 31, 2016; January 20, 2017; February 3, 2017; March 3, 2017;and June 12, 2017; 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) staff's original proposed no significant hazards consideration determination as published in the *Federal Register* on July 5, 2016 (81 FR 43666).

1.2 Background

General Site Information

Browns Ferry, Units 1, 2, and 3 are boiling-water reactor (BWR) plants of the BWR/4 design with Mark-1 containments located in Limestone County, Alabama, approximately 30 miles west of Huntsville, Alabama. The site contains approximately 840 acres and is located on the north shore of Wheeler Lake at Tennessee River Mile 294.

The construction permits for BFN, Units 1, 2, and 3 were issued by the Atomic Energy Commission (AEC) on May 10, 1967, for Units 1 and 2 and July 31, 1968, for Unit 3. The NRC originally licensed BFN Unit 1 on December 20, 1973, BFN Unit 2 on June 28, 1974, and BFN Unit 3 on August 18, 1976, for operation at original licensed power level 3293 MWt. Commercial operation of each unit, under Section 104(b) of the Atomic Energy Act of 1954, as amended, and the regulations of the AEC set forth in Part 50 of Title 10 of the *Code of Federal Regulations* (10 CFR Part 50) began on the following dates: Unit 1 on August 1, 1974, Unit 2 on March 1, 1975, and Unit 3 on March 1, 1977.

Licensing/Design Bases Information

The Browns Ferry units were designed and constructed based on the proposed General Design Criteria (GDC) published by the AEC in the *Federal Register* (32 FR 10213) on July 11, 1967 (hereafter called "draft GDC"). The AEC published the final rule that added Appendix A to 10 CFR Part 50, GDC for Nuclear Power Plants, in the *Federal Register* (36 FR 3255) on February 20, 1971 (hereafter called "final GDC").

Differences between the draft GDC and final GDC included a consolidation from 70 to 64 criteria. As discussed in the NRC Staff Requirements Memorandum (SRM) for SECY-92-223, dated September 18, 1992 (Reference 43), 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.

As discussed in Appendix A of the Updated Final Safety Analysis Report (UFSAR), the licensee has 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 design and licensing basis documentation.

Design Features

The three units share systems such as raw cooling water, emergency equipment cooling water, control air, and standby gas treatment. Units 1 and 2 share the vital electrical distribution system and four emergency diesel generators. Unit 3 has four emergency diesel generators.

TVA is authorized to use blended low enrichment uranium (BLEU) fuel in Units 1, 2 and 3. BLEU fuel is high enriched uranium from the Department of Energy that is down blended by

AREVA to create low enriched uranium dioxide fuel pellets that are loaded into BWR fuel assemblies.

By design, various systems are cross-tied to support multi-unit operation. For example, the 'A' loop of the Unit 2 Residual Heat Removal (RHR) System is available to support the RHR system for Unit 1 and vice versa, if needed. For the control rod drive (CRD) systems (CRDS), there is a swing pump between Units 1 and 2 in the event either of the main pumps is removed from service due to maintenance or a problem.

Equipment necessary to perform emergency operating instructions (EOIs), such as the Unit 1B CRDS pump (which can be used to supply water to Unit 2) and the standby liquid control (SLC) system (SLCS) boron tank concentration (in the event that the boron is needed to supply the other units), are maintained operable.

Previous Power Uprates

By Amendment No. 269, dated March 6, 2007 (Reference 44), for BFN Unit 1 and Amendment Nos. 254 and 214, dated September 8, 1998 (Reference 45) for BFN Units 2 and 3, the NRC granted power uprates of 5 percent, allowing the plant to be operated at the current licensed power level of 3458 MWt. Therefore, the proposed EPU would result in an increase of approximately 20 percent over the original licensed power level and 14.3 percent over the current licensed power level for BFN Units 1, 2, and 3.

1.3 Licensee's Approach

The licensee's application for the proposed EPU follows the guidance in the Office of Nuclear Reactor Regulation's (NRR's) Review Standard (RS)-001, "Review Standard for Extended Power Uprates," (Reference 46) to the extent that the review standard is consistent with the design basis of the plant. Where differences exist between the plant-specific design basis and RS-001, the licensee described the differences and provided evaluations consistent with the design basis of the plant.

The licensee submitted, by letter dated September 21, 2015 (Reference 1), a license amendment request (LAR) for an EPU for the Browns Ferry Plant. This submittal is referred to in this safety evaluation (SE) as "the LAR." Attachment 6 of the LAR provides a proprietary version of the General Electric (GE) Hitachi Nuclear Energy Americas LLC (GEH) Power Uprate Safety Analysis Report (PUSAR), NEDC-33860P, "Safety Analysis Report for Browns Ferry Nuclear Plant Units 1, 2, and 3 Extended Power Uprate." This report summarizes the results of safety analyses and evaluations performed that support the proposed increase in the authorized maximum steady-state reactor core power level. A non-proprietary version of this report is provided in the LAR, Attachment 7 (Reference 47)

As discussed in Section 2.1, "Power Uprate Safety Analysis Report," of the Enclosure to the LAR, the licensee also used the GEH Licensing Topical Report (TR) NEDC-33004P-A, "Constant Pressure Power Uprate," Revision 4, dated July 2003 (Reference 48), referred to in this SE as the CLTR. The CLTR provides an NRC-accepted approach for performing constant pressure power uprates (CPPU). The CPPU approach maintains a plant's current maximum operating reactor pressure. The constant pressure constraint along with other required limitations and restrictions are discussed in the CLTR. The CLTR provides a simplified approach to power uprate analyses and evaluations.

The evaluation methods and conclusions of the CLTR were approved for GE fuel up to and including GE14 fuel assemblies. The licensee stated that because BFN uses a mix of fuel types, the CLTR is not applicable for the fuel design-dependent topics and the associated analyses performed in support of the generic disposition in the CLTR are not applicable. Therefore, for fuel-dependent topics, the PUSAR follows the NRC-approved generic content for BWR extended power uprate (EPU) licensing reports documented in NEDC-32424P-A, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate" (Reference 49), which is commonly called "ELTR1." ELTR1 provides the generic criteria, methodology, and scope of evaluation required to provide sufficient information for use by the NRC for approval of applications for increases in the authorized thermal power level up to 20 percent. The process for evaluating safety issues for BWR EPUs is provided in the NRC-approved NEDC-32523P-A, "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate" (Reference 50), which is commonly called the "ELTR2." ELTR2 is a follow up report to ELTR1 that provides generic evaluations that are used by the licensees to reduce the content of plant-specific licensing applications. ELTR2 provides generic bounding results for BWR plant licensing issues, analytical studies and equipment evaluations.

TVA updated the PUSAR to incorporate the information submitted, as marked-up PUSAR pages, in previous BFN EPU LAR Supplements. Enclosure 1 to the TVA letter dated October 28, 2016 (Reference 37) provides a proprietary version of Revision 1 to the PUSAR (NEDC-33860P). Enclosure 2 to the TVA letter dated October 28, 2016, is a non-proprietary version of the document provided in Enclosure 1. Enclosures 1 and 2 replace and supersede Attachments 6 and 7, respectively, of the BFN EPU LAR (Reference 1).

The licensee supplemented the PUSAR by ANP-3403P, "Fuel Uprate Safety Analysis Report for Browns Ferry Nuclear Plant Units 1, 2, and 3 Extended Power Uprate," referred to in this SE as the FUSAR. FUSAR provides an integrated summary of the results of the safety analyses and evaluations performed in accordance with the CLTR, ELTR1, and ELTR2. The FUSAR supports operation of BFN Units 1, 2, and 3 at EPU conditions with AREVA's ATRIUM 10XM fuel. The FUSAR (ANP-3403) is provided in Attachment 8 (proprietary version) and Attachment 9 (non-proprietary version) of the BFN EPU LAR (Reference 1). Enclosures 1 (proprietary) and 2 (non-proprietary) of TVA letter dated December 15, 2015 (Reference 4), superseded and replaced Attachments 8 and 9 of the BFN EPU LAR (Reference 1) dated September 21, 2015.

The analyses in the PUSAR, FUSAR, and evaluations support the proposed increase of the maximum power level at BFN to 3952 MWt. These safety analyses also support elimination of the reliance on containment accident pressure (CAP) credit in demonstrating adequate net positive suction head (NPSH) for the emergency core cooling system (ECCS) pumps.

TVA submitted certain evaluations as separate attachments to the LAR. These evaluations include:

- TVA submitted "Heat Exchanger K Values Utilized in EPU Containment Analyses" in Attachment 39 (Reference 51) of the LAR. Enclosure 4 of the letter dated August 3, 2016 (Reference 30) superseded and replaced Attachment 39 of the BFN EPU LAR dated September 21, 2015.

- NEDO-33824, "Browns Ferry Replacement Steam Dryer Analysis" is submitted in Attachment 40 (proprietary version) and Attachment 41 (non-proprietary version) (Reference 52) of the LAR.

- TVA submitted "Transmission System Stability Evaluation (Critical Energy Infrastructure Information)" for Browns Ferry EPU in Attachment 43 (Reference 53) of the LAR, which is withheld from public disclosure under 10 CFR 2.390. Enclosure 2 of the TVA letter dated January 20, 2017 (Reference 39), provides Revision 4 of the Transmission System Stability Evaluation for Browns Ferry.

- TVA submitted the "Probabilistic Risk Assessment" for Browns Ferry EPU in Attachment 44 (Reference 54) of the LAR. Enclosure 5, "BFN EPU LAR, Attachment 44, Probabilistic Risk Assessment, Addendum (Revised)," of the TVA letter dated January 20, 2017 (Reference 39), provides a revision to Attachment 44 of the LAR.

- TVA submitted the "Flow Induced Vibration Analysis and Monitoring Program" for Browns Ferry in Attachment 45 (Reference 55) of the LAR. Enclosure 2 of the TVA letter dated July 13, 2016 (Reference 26), provides Revision 1 of the Flow Induced Vibration Analysis and Monitoring Program.

- TVA submitted the "Startup Test Plan" for Browns Ferry EPU in Attachment 46 (Reference 56) of the LAR.

The licensee provided summaries of the results of the analyses addressing the effect of operation of BFN Units 1, 2, and 3 at EPU conditions with ATRIUM 10XM fuel in the FUSAR and the fuel related reports. The fuel-related reports, included in Attachments 10 through 38 of the BFN EPU LAR (Reference 1) are listed below:

- ANP-3377, "Browns Ferry Units 1, 2, and 3 LOCA [Loss-of-Coolant Accident] Break Spectrum Analysis for ATRIUM 10XM Fuel (EPU)," is submitted in Attachments 10 (proprietary) and 11 (non-proprietary) (Reference 57) of the LAR.

- ANP-3378, "Browns Ferry Units 1, 2, and 3 LOCA-ECCS Analysis MAPLHGR Limits for ATRIUM 10XM Fuel (EPU)," is submitted in Attachments 12 (proprietary) and 13 (non-proprietary) (Reference 58) of the LAR.

- ANP-3384, "Browns Ferry Units 1, 2, and 3 LOCA-ECCS Analysis MAPLHGR Limits for ATRIUM-10 Fuel (EPU)," is submitted in Attachments 14 (proprietary) and 15 (non-proprietary) (Reference 59) of the LAR.

- ANP-3342, "Browns Ferry EPU (120% OLTP) Equilibrium Fuel Cycle Design (EPU)," is submitted in Attachments 16 (proprietary) and 17 (non-proprietary) (Reference 60) of the LAR.

- ANP-3372, "Browns Ferry Unit 3 Cycle 19 EPU (120% OLTP) LAR Reference Fuel Cycle Design (EPU)," is submitted in Attachments 18 (proprietary) and 19 (non-proprietary) (Reference 61) of the LAR.

- ANP-3404, "Browns Ferry Unit 3 Cycle 19 Representative Reload Analysis at Extended Power Uprate (EPU)," is submitted in Attachments 20 (proprietary) and 21 (non-proprietary) (Reference 62) of the LAR. Enclosures 3 (proprietary) and 4 (non-proprietary) of the TVA letter dated December 15, 2015 (Reference 4), superseded and replaced Attachments 20 and 21 of the BFN EPU LAR (Reference 1) dated September 21, 2015.

- ANP-3343, "Nuclear Fuel Design Report Browns Ferry EPU (120 percent OLTP) Equilibrium Cycle ATRIUM 10XM Fuel (EPU)," is submitted in Attachments 22 (proprietary) and 23 (non-proprietary) (Reference 63) of the LAR.

- ANP-3386, "Mechanical Design Report for Browns Ferry Units 1, 2 and 3 Extended Power Uprate (EPU) ATRIUM 10XM Fuel Assemblies (EPU)," is submitted in Attachments 24 (proprietary) and 25 (non-proprietary) (Reference 64) of the LAR.

- ANP-3385, "Mechanical Design Report for Browns Ferry Units 1, 2 and 3 Extended Power Uprate (EPU) ATRIUM-10 Fuel Assemblies (EPU)," is submitted in Attachments 26 (proprietary) and 27 (non-proprietary) (Reference 65) of the LAR.

- ANP-3388, "Fuel Rod Thermal-Mechanical Evaluation for Browns Ferry Extended Power Uprate (EPU)," is submitted in Attachments 28 (proprietary) and 29 (non-proprietary) (Reference 66) of the LAR.

- ANP-3327, "Evaluation of AREVA Fuel Thermal-Hydraulic Performance for Browns Ferry at EPU (EPU)," is submitted in Attachments 30 (proprietary) and 31 (non-proprietary) (Reference 67) of the LAR.

- FS1-0019629/30, "Browns Ferry Unit 3 Cycle 19 MCPR [minimum critical power ratio] Safety Limit Analysis with SAFLIM3D Methodology (EPU)," is submitted in Attachments 32 (proprietary) and 33 (non-proprietary) (Reference 68) of the LAR.

- ANP-2860 Revision 2, Supplement 2, Browns Ferry Unit 1 – Summary of Responses to Request for Additional Information, Extension for Use of ATRIUM 10XM Fuel for Extended Power Uprate (EPU), is submitted in Attachments 34 (proprietary) and 35 (non-proprietary) (Reference 69) of the LAR.

- ANP-2637, Boiling Water Reactor Licensing Methodology Compendium (EPU), is submitted in Attachments 36 (Reference 70) of the LAR.

- ANP-3409, Fuel-Related Emergent Regulatory Issues (EPU), is submitted in Attachments 37 (proprietary) and 38 (non-proprietary) (Reference 71) of the LAR.

The licensee plans to implement the EPU in one step. The licensee plans to make the modifications necessary to implement the EPU during the fall of 2018 refueling outage (RFO-U1R12) for Unit 1, during the spring of 2019 refueling outage (RFO-U2R20) for Unit 2, and the spring of 2018 refueling outage (RFO-U3R18) for Unit 3. Subsequently, the plant will be operated at 3952 MWt starting in Cycle 13 at Unit 1, Cycle 21 at Unit 2, and Cycle 19 at Unit 3.

1.4 Plant Modifications

The licensee has determined that several plant modifications are necessary to implement the proposed EPU. All EPU modifications, whether completed or being prepared, are in accordance with the TVA plant modifications and engineering change control process. Modifications not yet completed will be implemented during the above refueling outages for each unit, with the exception of the upgrades to the main generator excitation systems to address North American Electric Reliability Corporation (NERC) stability requirements. The licensee provided an updated discussion of the modifications required to support the EPU for the Browns Ferry units in Table 1 of Enclosure 7, "BFN EPU LAR, Attachment 47, List and Status of Plant Modifications, Revision 4," of (Reference 39). The following is a summary of these modifications and the licensee's proposed schedule for completing them.

Replacement Steam Dryers

TVA evaluated the existing BFN original equipment manufacturer steam dryers and determined that the steam dryers would not be suitable for EPU conditions without modifications. Therefore, TVA is replacing the existing BFN original equipment manufacturer steam dryers with replacement steam dryers (RSDs) manufactured by GEH. TVA is planning to install the RSDs during the fall 2018 outage for Unit 1, during the spring 2019 outage for Unit 2, and during the spring 2018 outage for Unit 3. Refer to Section 2.2.6, "Additional Review Area - Replacement Steam Dryer Structural Integrity," of this SE for additional information regarding the replacement steam dryer design and analyses.

Main Turbine

The licensee has completed the modification of the cross around relief valves and replacement/recalibration of the main steam system flow and pressure instruments. TVA is planning to replace the high pressure turbine rotor during the fall of 2018 outage for Unit 1, during the spring of 2019 outage for Unit 2, and during the spring of 2018 outage for Unit 3.

Turbine Sealing Steam

The size of the steam packing unloader valves and associated piping was increased to enable the turbine sealing system to accommodate EPU flow requirements.

Condensate Pumps

The condensate pumps were upgraded with new impellers and motors to accommodate the increased flows that will be required for EPU operation. In addition, an orifice plate was added, existing pump discharge check valves and pump suction strainers were replaced, motor protection relay settings were changed, and pump and motor instrumentation were replaced/recalibrated.

Condensate Booster Pumps

The condensate booster pumps and motors were replaced to increase pump capacity to accommodate the increased flows that will be required for EPU operation. In addition, air-cooled 1750 HP motors were replaced with water-cooled 3000 horsepower motors, existing

pump discharge check valves were replaced, motor protection relay settings were changed, and pump and motor instrumentation were replaced/recalibrated.

Condensate Pump and Condensate Booster Pump Area Ventilation

Additional cooling/ventilation was provided in the vicinity of the condensate and condensate booster pumps to accommodate the increased heat load resulting from larger air-cooled condensate pump motors and supplement cooling requirements for the hydrogen water chemistry main control panel.

Feedwater Pumps and Turbines

The licensee upgraded the following equipment in the feedwater system to provide increased feedwater flow for EPU operation.

- Replaced pumps with higher capacity pumps.
- Replaced turbine rotor, diaphragms and buckets.
- Replaced turbine/pump coupling.
- Upgraded seal water injection subsystem.

The licensee is planning to upgrade the feedwater control system software for EPU conditions during the fall of 2018 outage for Unit 1, during the spring of 2019 outage for Unit 2, and during the spring of 2018 outage for Unit 3.

Moisture Separators

The licensee modified the moisture separators' internals to increase moisture removal and accommodate increased flow at EPU conditions. This modification involved changing vanes and adding perforated plates on the moisture separators. The internal drains were also modified, as needed.

Feedwater Heaters

The feedwater heaters are upgraded or will be upgraded as follows:

- Re-rate the number 1, 2, and 3 feedwater heater shells to meet higher pressures, temperatures, and flows under EPU conditions. This modification is completed for all Browns Ferry units.
- Replace level control instrumentation on the number 1, 2, and 3 Feedwater Heaters to reduce susceptibility to flow induced turbulence. This modification is completed for all units.
- Provide additional welds and bracing to the pass partition plates for Nos. 1, 2, 3, and 5 feedwater heaters. This modification is completed for all units.

- Replace channel head relief valves for no. 3 feedwater heaters with valves having higher setpoints, and install a reinforcement ring on the manways for the number 3 and number 5 feedwater heaters due to the increase in tube-side design pressure with the increased head capacity of the condensate booster pumps. This modification is completed for Units 1 and 2, and will be completed during the spring of 2018 outage for Unit 3.

- Replace the upper shell and install an extraction steam inlet duct to minimize heater shell erosion and preclude tube damage from steam jet impingement on each of the number 3 feedwater heaters. This modification is completed for all units.

- Replace the tube bundle and channel head in No. 4 feedwater heaters with a design less susceptible to damage from flow induced vibration. This upgrade will be completed during the fall of 2018 outage for Unit 1, during the spring of 2019 outage for Unit 2, and during the spring of 2018 for Unit 3.

Main Condenser Extraction Steam Bellows

Main condenser extraction steam bellows Nos. 2, 3, 4 and 5 were replaced with bellows accommodating higher design temperatures and pressures for EPU.

Condensate Demineralizers

A 10th condensate demineralizer, and associated valves and controls, were installed on each unit to accommodate the increased condensate flow associated with EPU operation.

Steam Packing Exhauster Bypass

The capacity of the steam packing exhauster bypass line was increased by installing larger piping and flow control valves to accommodate an increased flow under EPU conditions.

Torus Attached Piping

An existing pad at an ECCS ring header branch connection was reinforced for Units 2 and 3 to address higher pipe stresses associated with EPU conditions. This modification was not required for Unit 1.

Main Steam Supports

The licensee modified one BFN Unit 2 main steam pipe support due to increased loads resulting from turbine stop valve closure at EPU steam flow rates. All other existing BFN Unit 2 main steam pipe supports, and all main steam pipe supports on BFN Units 1 and 3, were determined to have sufficient design margin to accommodate the increased turbine stop valve closure loads.

Reactor Recirculation Pumps & Motors

The reactor recirculation system is upgraded for all units as follows:

- Performed analyses/evaluations to increase design ratings for recirculation pumps and motors.
- Upgraded variable frequency drive control system.
- Performed pump and motor instrumentation upgrades.

TVA will revise the upper power runback setting for EPU conditions during the fall of 2018 outage for Unit 1, during the spring of 2019 outage for Unit 2, and during the spring of 2018 outage for Unit 3.

Jet Pump Sensing Line Clamps

Jet pump sensing line clamps were installed to reduce pipe vibration under EPU conditions.

Main Generator System

The main generators were upgraded to 1330 megavolts-ampere (MVA) for BFN Unit 1 and 1,332 MVA for BFN Unit 3. A rewound stator was installed to support higher generator output capacity; stator water cooling instruments were replaced; and SWC flow, pressure, differential pressure, and temperature settings were changed to support the increased stator water cooling requirements. The main generator for BFN Unit 2 will be upgraded to 1,332 MVA during the spring of 2019 outage.

Main Generator Hydrogen Pressure

TVA plans to increase generator hydrogen pressure from 65 pounds per square inch gauge (psig) to 75 psig to support EPU operation. The licensee plans to perform the following modifications during the fall of 2018 outage for BFN Unit 1, during the spring of 2019 outage for BFN Unit 2, and during the spring of 2018 outage for BFN Unit 3.

- Change pressure regulating valve settings and pressure alarm setting.
- Replace pressure switches as needed for new operating range.
- Change generator field over-excitation relay settings.
- Eliminate hydrogen flow integrator to mitigate hydrogen leakage.

Isophase Bus Duct Cooling

The licensee modified the isophase bus duct cooling system to remove increased bus duct heat under EPU conditions by replacing cooling fans and motors, and replacing cooling coils.

Main Bank Transformers

The main bank transformers were upgraded as follows to account for the higher power output from the main generators at EPU conditions.

- Replaced three 500 MVA transformers per unit.
- Replaced one 500 MVA spare transformer for Units 1 and 2.
- Installed a new dedicated Unit 3 500 MVA spare transformer.

Vibration Monitoring

TVA plans to install mounting brackets/supports and temporary instrumentation for vibration monitoring during EPU power ascension during the fall of 2018 outage for BFN Unit 1, during the spring of 2019 outage for BFN Unit 2, and during the spring of 2018 outage for BFN Unit 3.

Main Steam Isolation Valves (MSIV)

Longer stroke actuators were installed to move the poppet further out of the flow stream. Additional modifications were performed to improve the performance of the MSIVs including new bonnets, nose guided poppets (trimmed profile), and larger diameter valve stems.

Electro-Hydraulic Control (EHC) Software

EHC software including an electrical overspeed set point, intermediate pressure, power load unbalance, turbine first stage pressure, and megawatt (MW) control, were revised to address changes in plant parameters required to support the EPU.

Technical Specification Instrument Respan

The licensee plans to perform the following TS instrument respan and setpoint changes for EPU during the fall of 2018 outage for BFN Unit 1, during the spring of 2019 outage for BFN Unit 2, and during the spring of 2018 outage for BFN Unit 3.

- Turbine 1st stage pressure scram bypass permissive setpoint change.
- Main steam line high flow isolation channel respan.
- APRM (average power range monitor) flow biased and setdown instrument respan and setpoint change

Balance of Plant Instrument Respan

The following balance of plant (BOP) instruments are respanned or replaced for the EPU:

- Update hydrogen water chemistry programmable logic controller software for control of hydrogen and oxygen injection at EPU conditions.
- Replace and respan hydrogen water chemistry flow instruments.
- Replace and respan extraction steam pressure instruments.

- Replace and respan feedwater heater pressure and level instruments.
- Recalibrate setpoints for reactor feedwater low suction and steam jet air ejector stage I/II/III low pressure switches.
- Respan high pressure turbine exhaust intermediate pressure transmitter.
- Replace and respan offgas condenser cooling water temperature instruments.

Condenser Instrumentation

Condenser instrumentation is upgraded for improved reliability and performance monitoring under EPU conditions.

- Replace/relocate condenser A/B/C hotwell pressure transmitters to improve inputs to the integrated computer system (ICS).
- Add condenser circulating water (CCW) inlet/outlet temperature inputs to the integrated computer system (ICS).
- Respan condenser A/B/C CCW outlet flow channels and add to the ICS.
- Revise reactor feed pump turbine trip to two out of three logic.
- Modify the steam jet air ejector (SJAE) instrumentation set point to remove the trip on low condenser vacuum and eliminate the auto-start of standby SJAE.

The licensee plans to complete the following upgrades during the fall of 2018 outage for BFN Unit 1, during the spring of 2019 outage for BFN Unit 2, and during the spring of 2018 outage for BFN Unit 3.

- Install nine new condenser vacuum pressure transmitters per unit (three on each condenser) and provide condenser vacuum pressure signals to the EHC system.
- Move condenser A/B/C low vacuum alarm, low vacuum turbine trip and low vacuum bypass trip functions to the EHC logic (previously performed by pressure switches).
- Perform hardware and software changes to the EHC system to support the new alarm and trip functions.

Steam Jet Air Ejector Pressure switches

Setpoints for SJAE condensate pressure switches were revised to prevent inadvertent SJAE isolation.

Main Steam Acoustic Vibration Suppressors

Acoustic vibration suppressors (AVS) were installed inside the main steam 6 inch diameter blind flanged branch lines to reduce acoustic loading on the steam dryer.

Standby Liquid Control (SLC) System

The licensee plans to increase the shutdown capability of the SLC system to support the containment accident pressure credit elimination during an ATWS event as discussed in PUSAR (Reference 47), Section 2.8.4.5.3 by increasing the Boron-10 enrichment during the fall of 2018 outage for BFN Unit 1, during the spring of 2019 outage for BFN Unit 2, and during the spring of 2018 outage for BFN Unit 3.

Hardened Wetwell Vent

The licensee stated that in response to EA-13-109, "Order Modifying Licenses with Regard to Reliable Hardened Containment Vents Capable of Operation Under Severe Accident Conditions," the hardened wetwell vent will be modified to provide individual vent lines for each BFN unit. The original hardened wetwell vent capacity would be reduced from 1.0 percent to 0.88 percent of rated thermal power under EPU conditions. The licensee completed this modification for BFN Unit 1 in the fall of 2016 and for BFN Unit 2 in the spring of 2017. The licensee plans to implement the same modification during the spring of 2018 outage for BFN Unit 3. Upon the completion of this modification, all three BFN units' hardened wetwell vent capacities will be increased from 0.88 percent to 1.0 percent of rated thermal power under EPU conditions.

Self-Excited Excitation System

The licensee plans to upgrade the excitation system on Units 1, 2, and 3 by installing a self-excited excitation system during the fall of 2020 for Unit 1, during the spring of 2021 for Unit 2, and during the spring of 2020 for Unit 3. The excitation system will be returned to a self-excited, shaft driven alternator and the Automatic Voltage Regulator (AVR) will be modified. The AVR will be supplied power with exciter fed, redundant excitation transformers. The licensee noted that during the interim period of EPU operation preceding installation of the self-excited excitation system that transmission system grid stability will be maintained through the use of a detailed temporary operating guide.

Alternate Leakage Treatment Pathway

The licensee plans to provide a highly reliable alternate leakage treatment pathway that routes 99.5 percent of the leakage from the primary containment MSIVs directly to the condenser during the fall of 2018 outage for Unit 1, during the spring of 2019 outage for Unit 2, and during the spring of 2018 outage for Unit 3. The modification on each unit will include replacement of five motor operated valves on the main steam drain lines with air operated valves. Also, an additional main steam drain line valve will be installed, with an air operator, to address single failure criteria. All the new air operated valves will fail open on loss of electrical power or control air.

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

1.5 Method of NRC Staff Review

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

The NRC staff's review of the BFN Units 1, 2, and 3 EPU LAR and its supplements is based on RS-001 (Reference 46). RS-001 contains guidance for evaluating each area of review in the application, including the specific GDC used as the NRC's acceptance criteria. The guidance in RS-001 is based on the final GDC, whereas Browns Ferry was designed and constructed based on the draft GDC.

TVA submitted in EPU LAR (Reference 1), Attachment 48, "RS-001 SE Template GDC Markup (with redline/strike out)," that provided a matrix that cross-references the draft GDC to the final GDC and a revision to the template SE in RS-001 replacing the numeric values of the final GDC with the corresponding TVA design criteria and draft GDC that constitute the current licensing basis. Related changes to TVA plant-specific design criteria were also incorporated in the revised template.

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

- Audit in Support of Replacement Steam Dryer Review Associated with Extended Power Uprate License Amendment Request, April 19 to April 21, 2016 (Refer to audit report dated June 23, 2016 (Reference 72)).

- Audit in Support of Containment Accident Pressure Associated with Extended Power Uprate License Amendment Request, May 3 to May 5, 2016 (Refer to audit report dated July 14, 2016 (Reference 73)).

- Audit in Support of Spent Fuel Pool Criticality and Boral Monitoring Program Reviews Associated with Extended Power Uprate License Amendment Request, May 10 to May 11, 2016 (Refer to audit report dated July 14, 2016 (Reference 74)).

The NRC staff performed independent confirmatory calculations in relation to the following topics:

- Pressure-Temperature Limits and Upper-Shelf Energy (see Section 2.1.2 of this SE).

- Control rod drop accident (CRDA) dose (see Section 2.9.2.2 of this SE).

In areas where the licensee and its contractors used NRC-approved or widely accepted methods in performing analyses related to the proposed power uprate, 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 uprate conditions. Details of the NRC staff's review and the results of the independent calculations are discussed in Section 2.0 of this SE.

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) draft GDC-9, insofar as it requires that the reactor coolant pressure boundary (RCPB) be designed and constructed so as to have an exceedingly low probability of gross rupture or significant leakage; (2) draft GDC-33, insofar as it requires that the RCPB be capable of accommodating without rupture, and with only limited allowance for energy absorption through plastic deformation, the static and dynamic loads imposed on any boundary component as a result of any inadvertent and sudden release of energy to the coolant; (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; (4) 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 (5) 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) (Reference 75) 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 the American Society for Testing and Materials (ASTM) International Standard, ASTM E185-82, "Standard Practice for Conducting Surveillance Tests for Light-Water Cooled 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 EPU on the reactor pressure vessel (RPV) material surveillance program in Section 2.1.1, "Reactor Vessel Material Surveillance Program," of PUSAR (Reference 37). Browns Ferry design criteria predate the GDC criteria, and their conformance with the intent of the GDC was established in the BFN final safety analysis report (FSAR), Appendix A. Since then, the NRC staff's evaluation of the BFN reactor vessel material surveillance program (e.g., NUREG-1843, "Safety Evaluation Report Related to the License Renewal of the Browns Ferry Nuclear Plant, Units 1, 2, and 3," (Reference 76)) focused on compliance with the requirements of 10 CFR Part 50, Appendix H.

The licensee, in Section 2.1.1 of PUSAR provided the status of the capsule withdrawal for the three units and stated that "Browns Ferry Units 1, 2, and 3 are part of the BWR Vessel and Internals Project (BWRVIP) Integrated Surveillance program (ISP) currently administered by the Electric Power Research Institute (EPRI) and will comply with the withdrawal schedule specified for representative or surrogate surveillance capsules that now represent each unit." Therefore, the licensee determined that implementation of the EPU has no adverse effect on the BWRVIP withdrawal schedule.

BWRVIP-86, Rev. 1-A, "Updated BWR Integrated Surveillance Program (ISP) Implementation Plan" (Reference 77), 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 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 also establishes acceptable technical criteria for capsule withdrawal and testing. The NRC's SE that is enclosed in BWRVIP-86, Revision 1-A confirms that the ISP requirements comply with the requirements established in Appendix H to 10 CFR Part 50.

For BFN units, the NRC staff verified that implementation of the BWRVIP ISP was approved on August 14, 2008, for Unit 1 (Reference 78) and January 28, 2003, for Units 2 and 3 (Reference 79). BWRVIP ISP indicated that BFN Unit 1 and Unit 3 will rely on the surveillance information from BFN Unit 2 for plant-specific RPV embrittlement monitoring. However, the basis for choosing the materials for surveillance was not provided in Section 2.1.1 of PUSAR, nor did the licensee provide sufficient information to demonstrate that the ISP withdrawal schedule for the BFN units is in accordance with ASTM E185-82 and NUREG-1801, "Generic Aging Lessons Learned (GALL) Report" (Reference 80) for vessel surveillance programs.

The NRC staff's evaluation of these two aspects of the BWRVIP ISP applicable to the Browns Ferry EPU follows. Regarding choosing the materials for surveillance, BWRVIP-86, Rev. 1-A shows that the surveillance weld and plate for BFN Unit 2 are the electro-slag weld (ESW) and the A0981-1 plate. The NRC staff confirmed that the materials chosen for surveillance are representative for Unit 2 because the limiting RPV weld is an ESW (Table 2.1-2b of PUSAR) and the limiting RPV plate C2467-1 is adequately represented by the surveillance plate A0981-1 (also Table 2.1-2b of PUSAR). This adequacy is established by the proximity (differ within 8 percent) of the adjusted reference temperature (ART) at one-quarter of the RPV wall thickness (1/4T) from the clad/base metal interface for 48 effective full-power years (EFPYs) between the limiting RPV plate and the RPV plate having the same heat number as the surveillance plate. BFN Unit 1 and Unit 3 rely on the surveillance information from BFN Unit 2 for plant-specific RPV embrittlement monitoring because, in addition to meeting the Appendix H requirements for an ISP for the three units (Reference 78) and (Reference 79), the limiting RPV material for all three units is ESW and the chemistry of the surveillance weld and plate for Unit 2 bound the chemistry of the surveillance weld and plate for Units 1 and 3 (Tables 3-2 and 3-3 of Ref. 102). Thus, the NRC staff confirmed that the materials chosen for surveillance in the BWR ISP are adequate for BFN, Units 1, 2, and 3 and meet the intent of ASTM E185, which requires the most limiting RPV materials be selected as the surveillance materials.

Regarding the aspect of lacking sufficient information in PUSAR and in BWRVIP-86 (Reference 77), the NRC letter to TVA dated August 14, 2008 (Reference 78), and the NRC letter to TVA dated January 28, 2003 (Reference 79), to demonstrate that the BWRVIP ISP withdrawal schedule for BFN units is in accordance with ASTM E185 and the GALL

supplemental guidance, the NRC staff noticed the following supporting statement in Amendment 26 (BFN-26):

> Since the predicted adjusted reference temperature of the reactor vessel beltline steel is less than 100 °F at end-of-life, the use of the capsules per the ISP meets the requirements of 10 CFR 50, Appendix H, and ASTM E185-82.

This statement is identical to that in BFN-19 (Enclosure 2 of the LAR for implementation of BWRVIP ISP for Units 2 and 3) that was approved in (Reference 79). However, "adjusted reference temperature" in the quote appears to be incorrect. The correct terminology per ASTM E185-82 is "transition temperature shift," which is further explained in Article 4.15 of this standard as "ΔRT_{NDT}," consistent with the terminology in Regulatory Guide (RG) 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," May 1988 (Reference 81). ART, however, has a different meaning, as defined in RG 1.99;

$$ART = \text{initial } RT_{NDT} + \Delta RT_{NDT} + \text{Margin}$$

This definition has been adopted by almost all utilities. Hence, the NRC staff requested clarification of the statement in BFN-26 regarding the BWRVIP ISP capsules for the BFN units.

The licensee, in its response dated April 14, 2016 (Reference 13), indicated that based on a review of the 10 CFR Part 50, Appendix H requirements and the ASTM E185-82 guidance, TVA will revise the quoted statement in UFSAR BFN-26 by replacing "adjusted reference temperature" with "transition temperature shift." Thus, this issue was resolved.

To verify the validity of the quoted BFN-26 statement, the NRC staff reviewed Table 2.1-2a (Unit 1), Table 2.1-2b (Unit 2), and Table 2.1-2c (Unit 3) of PUSAR, and found that the end of life (EOL) transition temperature shifts (ΔRT_{NDT}s) under the proposed EPU for all three units are below 100 °F. Therefore, the number of capsules (i.e., 3) for the BFN units per the BWRVIP ISP meets the requirements of 10 CFR 50, Appendix H, and ASTM E185-82. The remaining issue to be verified is that the capsule withdrawal schedule for the last capsule (the first capsule was withdrawn in 1994 and the second capsule was withdrawn in 2011) meets 10 CFR Part 50, Appendix H and ASTM E185-82 requirements. ASTM E185-82 states that the third capsule of a 3-capsule surveillance program should be withdrawn "no less than once or greater than twice the peak EOL vessel fluence." UFSAR BFN-26 states that the third capsule of BFN, Unit 2 is currently scheduled for removal in the refueling outage closest to 40 EFPYs of operation without exceeding it. This is consistent with the BWRVIP ISP schedule and the ASTM E185-82 requirement to have the third capsule withdrawn between 32 EFPYs and 64 EFPYs of RPV operation, providing adequate vessel embrittlement information for the period of extended operation for the BFN units. Operating under the EPU will not change this withdrawal schedule. It simply means that under the EPU the capsule will experience higher neutron fluence at 40 EFPYs and 64 EFPYs. Therefore, the NRC staff concludes that, for the BFN units, the BWRVIP ISP meets the requirements of 10 CFR Part 50, Appendix H, and ASTM E185-82 under the EPU until the scheduled year of 2026 for the third capsule withdrawal. It should be noted that the GALL Aging Management Program (AMP) XI.M31 extended this guidance to the end of the period of extended operation and requires that the surveillance program have at least one capsule with a projected neutron fluence equal to or exceeding the 60-year peak reactor vessel wall neutron fluence prior to reaching the end of the period of extended operation. For the BFN units, the end of the period of extended operation equates to 54 EFPYs for Unit 1 and 52 EFPYs for Units 2 and 3. To ensure that the BWRVIP ISP supports the GALL AMP XI.M31

guidance, the NRC staff requested the licensee to (1) confirm that the withdrawal date for the third capsule in 2026 will not be changed due to higher neutron fluence under EPU and (2) explain how the withdrawal date for the remaining stand-by capsule (the fourth capsule) in BFN, Unit 2 will be determined to meet the GALL AMP XI.M31 guidance.

The license responded, in its letter dated April 14, 2016 (Reference 13), that "BFN Unit 2 is currently scheduled to withdraw the third capsule in early 2027." This confirmed that the EPU has only a small effect on the capsule withdrawal schedule. In response to part 2 of the request for additional information (RAI)-2, the licensee stated that, "the fourth capsule is accumulating fluence at approximately the same rate as the vessel ID, i.e., lead factor ~1." This means that the BWRVIP ISP meets the GALL AMP XI.M31 guidance because the fourth BFN Unit 2 capsule will have a projected neutron fluence equal to the 60-year peak reactor vessel wall neutron fluence prior to reaching the end of the period of extended operation. The licensee further stated that, "BFN is committed to the BWRVIP ISP program and will support the program through additional capsule withdrawals as deemed appropriate by the BWRVIP and NRC," confirming that the withdrawal date of any stand-by capsule, to be reported in the next revision of BWRVIP ISP, will be reviewed by the NRC. Therefore, the NRC staff concludes that the licensee's RPV material surveillance program for BFN, Units 1, 2, and 3 will remain in compliance with the requirements specified in Appendix H to 10 CFR Part 50, ASTM E185-82, and GALL AMP XI.M31, 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 draft GDC-9 and 33, 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

Pressure-temperature (P-T) limits are established in 10 CFR Part 50, Appendix G to ensure the structural integrity of the ferritic components of the reactor coolant pressure boundary (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 EFPYs specified for the proposed EPU, considering neutron embrittlement effects and using linear elastic fracture mechanics. Separately, upper-shelf energy (USE) requirements are also established in Appendix G to ensure the structural integrity of the RPV. The NRC's acceptance criteria for P-T limits 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; (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

Pressure-temperature 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 American Society of Mechanical Engineers (ASME) Boiler & Pressure Vessel Code (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 ART values used for P-T limits calculations are specified in RG 1.99 (Reference 81).

The licensee's evaluation of the impact on the current P-T limits due to the EPU is documented in Section 2.1.2, "Pressure-Temperature Limits and Upper-Shelf Energy," of the PUSAR. The licensee stated that the current P-T limits have been developed for EPU conditions, including consideration of the N-16 water level instrumentation nozzle. It further concluded that, "TVA has evaluated the effects of the proposed EPU on the P-T limits for the plant and addressed changes in neutron fluence and their effects on the P-T limits."

The NRC staff independently confirmed that the ART values and their inputs and calculation in Table 2.1-2a (for 38 EFPYs), Table 2.1-2b (for 48 EFPYs), and Table 2.1-2c (for 54 EFPYs) of PUSAR for BFN, Units 1, 2, and 3 are identical to corresponding tables in NEDC-33445P for Unit 1 (Reference 82), NEDC-33854P for Unit 2 (Reference 83), and NEDC-33857P for Unit 3 (Reference 84), supporting the current P-T limits that were approved on February 2, 2015 for BFN Unit 1 (Reference 85); June 2, 2015 for BFN Unit 2 (Reference 86); and January 7, 2016 for BFN Unit 3 (Reference 87). Consequently, the current P-T limits for BFN, Units 1, 2, and 3 remain valid and acceptable because they were conservatively developed based on the identical ART values at higher fluences under EPU conditions.

Upper-Shelf Energy Calculations

The regulations in Appendix G to 10 CFR Part 50 provide 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 ASME 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 RG 1.99 (Reference 81).

Projected USE values for RPV materials are calculated based on the projected neutron fluence at a postulated flaw depth at 1/4T, weight percentage (wt. %) copper in the material, and the initial USE value for the material prior to exposure to neutron radiation. Initial USE values are unavailable for BFN units beltlines, therefore, projected USE values were generated by the licensee via an equivalent margin analysis (EMA) documented in NEDO-32205-A, Revision 1, "10 CFR 50 Appendix G Equivalent Margin Analysis for Low Upper Shelf Energy in BWR/2-6 Vessels," (Reference 88) to determine compliance with the USE requirements of 10 CFR Part 50, Appendix G for 40 years of operation. The USE EMA was later updated via BWRVIP-74, "BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines for License Renewal," (Reference 89) for 60 years of operation, which was reviewed and approved by the NRC staff in 2001 (Reference 90). The approved version of BWRVIP-74 (i.e., BWRVIP-74-A) is classified as proprietary.

TVA's demonstration of compliance with 10 CFR Part 50, Appendix G regarding USE for 60 years of operation for BFN units (end-of-license-extension (EOLE) 1/4T neutron fluence of 1.35×10^{18} n/cm^2 for Unit 1, 2.3×10^{18} n/cm^2 for Unit 2, and 1.59×10^{18} n/cm^2 for Unit 3) was approved, as documented in NUREG-1843. The USE evaluation was based on BWRVIP-74-A. The NRC staff found that for the EPU conditions in the PUSAR, the 1/4T neutron fluence is 1.09×10^{18} n/cm^2 for plate and 8.86×10^{17} n/cm^2 for weld at 38 EFPYs for Unit 1; 1.34×10^{18} n/cm^2 for plate and 9.14×10^{17} n/cm^2 for weld at 48 EFPYs for Unit 2; and 1.25×10^{18} n/cm^2 for plate and 1.05×10^{18} n/cm^2 for weld at 54 EFPYs for Unit 3. It is clear that all EPU 1/4T neutron fluence values from Attachment 6 for the BFN units are bounded by the corresponding neutron fluence values used for the USE evaluation in NUREG-1843. However, Tables 2.1-1a, 2.1-1b, and 2.1-1c of the PUSAR indicate that the USE decrease is based on the surveillance data for only the BFN, Unit 1 limiting beltline weld, while the current P-T limits approved in February 2, 2015, for BFN Unit 1; June 2, 2015, for BFN Unit 2; and January 7, 2016 for BFN Unit 3, which are confirmed by the NRC staff to be identical to the P-T limits under EPU conditions, indicate that surveillance data from the BWRVIP ISP is also available for the limiting weld for Units 2 and 3. As a result, the NRC staff requested the licensee to explain why surveillance data is not in the USE evaluations of the limiting beltline weld for BFN Units 2 and 3 while the P-T limit evaluations are based on the available surveillance data.

The licensee, in its response dated April 14, 2016 (Reference 13), indicated that the BWRVIP ISP surveillance data was considered in the weld evaluation in Table 2.1-1b for Unit 2, but not in Table 2.1-1c for Unit 3 because the surveillance weld is not the same heat as that in the Unit 3 vessel and is not applicable to BFN Unit 3. The NRC staff verified that Table 2.1-1b did not use the surveillance weld information because the surveillance weld showed less USE reduction. Further, for the BFN Unit 3 P-T limits, the ART based on the surveillance weld was calculated for information only, it is not used to develop the approved P-T limits. Therefore, the NRC staff concluded that the licensee is consistent in applying surveillance data to P-T limits and USE evaluations.

Based on the above evaluation, the NRC staff determined that the NUREG-1843 conclusion that the BFN units are in compliance with 10 CFR Part 50, Appendix G regarding USE at the EOLE neutron fluence applies to the EPU period, and the NRC staff concludes that the BFN, Units 1, 2, and 3 RPV beltline materials will maintain sufficient USE for 38, 48, and 54 EFPYs, respectively, under EPU conditions.

Reactor Pressure Vessel Circumferential and Axial Weld

The ASME Code, Section XI, Table IWB-2500-1 requires inspection of all RPV welds at regular intervals. On May 31, 2005 (Reference 91), August 14, 2000 (Reference 92), and November 18, 1999 (Reference 93), the NRC granted separate reliefs from performing the ASME Code, Section XI-required examinations of the BFN, Units 1, 2, and 3 RPV circumferential welds for the original 40-year licensed operating period, under pre-EPU operating conditions. The basis for this relief was the BWRVIP-05 report, "BWR Reactor Pressure Vessel Shell Weld Inspection Recommendation," dated September 28, 1995 (Reference 94) and the accompanying July 28, 1998, SE (Reference 95), which 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 staff 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 the BWRVIP-05 report. The BWRVIP-05 report and the staff's SE (Reference 95) provide the basis for granting relief to the licensee from performing volumetric examinations of the RPV circumferential welds for the remainder of the original 40 years.

The NRC staff's SE (Reference 95) provides a limiting conditional failure probability of 4.83×10^{-4} per reactor year for a limiting plant-specific mean RT_{NDT} of 129.4 °F for Babcock & Wilcox (B&W)-fabricated RPVs at 64 EFPYs. The NRC staff confirmed that the mean RT_{NDT}s of the circumferential welds at BFN, Units 1, 2, and 3 are projected to be 106 °F, 20 °F, and 24 °F respectively at the end of 38 EFPYs, 48 EFPYs, and 54 EFPYs, the same as the licensee's values reported in Table 2.1-3 of PUSAR. 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 BFN, Units 1, 2, and 3 are significantly lower than that for the limiting plant-specific case for B&W-fabricated RPVs, indicating that the conditional failure probability of the BFN, Units1, 2, and 3 circumferential welds are much less than 4.83×10^{-4} per reactor year. Based on the above, the NRC staff concludes that the BFN, Units 1, 2, and 3 RPV circumferential weld parameters will continue to be bounded by the BWRVIP-05 parameters discussed above as extended in (Reference 96).

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 (GL) 98-05 (Reference 97) would remain in place post EPU, which the licensee confirmed in its letter dated April 14, 2016 (Reference 13).

TVA did not address reactor vessel axial weld failure probability in the EPU application. However, this issue was addressed for Units 2 and 3 in the 2004 license renewal application and addressed by the NRC staff for BFN Unit 1 in NUREG-1843. The NRC staff reviewed this information and confirmed that the axial weld neutron fluence at 38, 48, and 54 EFPYs under EPU conditions for BFN, Units 1, 2, and 3 (1.58×10^{18} n/cm^2, 1.32×10^{18} n/cm^2 and, 1.52×10^{18} n/cm^2) are bounded by the EOLE neutron fluence (2.4×10^{18} n/cm^2, 2.3×10^{18} n/cm^2, and 2.3×10^{18} n/cm^2). Hence, the staff determined that the NUREG-1843 conclusion that failure frequencies for BFN, Units 1, 2, and 3 axial welds will be less than 5×10^{-6} per reactor-year of operation at the EOLE neutron fluence applies to the EPU period.

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 and axial weld properties. The NRC staff concludes that the licensee has adequately addressed the impact of the EPU on the BFN, Units 1, 2, and 3 USE, P-T limits, and RPV circumferential weld properties. Specifically, the NRC staff concludes that (1) the BFN, Units 1, 2, and 3 RPV beltline materials will remain acceptable, with respect to the USE, under EPU conditions, through 38, 48, and 54 EFPYs respectively; (2) the licensee has addressed the impact of the EPU on the ART values and, subsequently, the P-T Limits for the RPV beltline materials; and (3) the RPV circumferential weld properties under EPU conditions through the specified EFPYs will remain bounded by the NRC failure probability analysis in the July 28, 1998 SE on BWRVIP-05. Based on the above, the NRC staff concludes that BFN, Units 1, 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 draft GDC-9 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 proposed P-T limits.

2.1.3 Reactor Internal and Core Support Materials

Regulatory Evaluation

The reactor vessel internals (RVI) components 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 reviewed the materials' specifications, mechanical properties, welds, weld controls, nondestructive examination (NDE) procedures, corrosion resistance, and susceptibility to degradation for these components. The NRC's acceptance criteria for RVI and core support materials are based on draft GDC-1 and 10 CFR 50.55a. Specific review criteria are contained in SRP Section 4.5.2 and Boiling Water Reactor Vessel and Internals Project (BWRVIP)-26 (Reference 98).

Technical Evaluation

The licensee discussed the impact of the EPU on the BFN, Units 1, 2, and 3 RVI components in Section 2.1.3, "Reactor Internal and Core Support Materials," of PUSAR (Reference 37). The licensee assessed the RVI components and found them acceptable for continued operation through the end of the currently licensed period of operation under EPU conditions.

The licensee's RVI and core support materials evaluation addressed the materials specifications, mechanical properties, welds, weld controls, NDE procedures, corrosion resistance, and susceptibility to degradation of the RVI and core supports. These RVI and core supports include SSCs that perform safety functions or whose failure could affect safety functions performed by other SSCs, as discussed in the regulatory evaluation. 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.

The licensee discussed the potential for irradiation-assisted stress-corrosion cracking in RVI and core support components. To address this potential, the licensee has a procedurally

controlled program for the augmented NDE 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 irradiation-assisted stress-corrosion cracking (IASCC) in welds and adjacent base materials. The licensee states that implementation of the procedurally controlled program at Browns Ferry is consistent with the BWRVIP issued documents.

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 GEH Service Information Letters. The inspection program provides performance frequency for NDE 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 (ID) 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 EFPYs for Unit 1 and 52 EFPYs for Units 2 and 3. This neutron fluence threshold was established by GE as mentioned in BWRVIP-26-A, "BWR Top Guide Inspection and Flaw Evaluation Guidelines" (Reference 98). The NRC staff found additional information regarding this threshold in Appendix B of MRP-175, "PWR Internals Material Aging Degradation Mechanism Screening and Threshold Values" (Reference 99), which indicated that this neutron fluence threshold is based on BWR and PWR RVI component failure experience. As discussed earlier, the licensee's implementation of the procedurally controlled program is consistent with the BWRVIP issued documents. Therefore, for these three identified RVI components susceptible to IASCC, the licensee's management of the effects of IASCC relies on the inspection recommendations in the following BWRVIP reports:

- Top Guide (BWRVIP-26-A and BWRVIP-183) ((Reference 98) and (Reference 100)).
- Shroud (BWRVIP-76, Revision 1) (Reference 101).
- Core Plate (BWRVIP-25) (Reference 102).

Since the final SE on BWRVIP-76, Revision 1, "BWR Core Shroud Inspection and Flaw Evaluation Guidelines" contains no limitation or condition, referencing BWRVIP-76, Revision 1 is equivalent to referencing BWRVIP-76, Revision 1-A. However, this is not the case for BWRVIP-183, "Top Guide Grid Beam Inspection and Flaw Evaluation Guidelines" (Reference 100). The final SE for BWRVIP-183 issued on December 31, 2015, contains conditions, and, therefore, the licensee shall implement BWRVIP-183-A in accordance with BWRVIP-94-NP, Revision 2, "Program Implementation Guide" (Reference 103).

For these three components, the NRC staff requested the licensee clarify whether the fluence values were specifically developed for the EPU condition. The licensee, in its response dated April 14, 2016 (Reference 13) clarified that the fluence values for these three components were not specifically developed for the EPU condition. However, these fluence values, which were used originally to support the license renewal application of BFN units, bounds the EPU conditions.

Top guide inspection requirements are specified in BWRVIP-26-A (Reference 98). Later, a concern for potential cracking in multiple top guide beams prompted the BWRVIP to address this issue in BWRVIP-183. In Section 2.1.3 of PUSAR the applicant listed both BWRVIP-26-A and BWRVIP-183 as guidance references to manage the effects of IASCC in top guide and top guide grid beams. The applicant also confirmed that no relevant indications have been observed in the most recent grid beam inspections of BFN, Units 1, 2, and 3.

Core shroud inspection requirements are specified in BWRVIP-76, Revision 1-A (Reference 101). Although Section 2.1.3 of the PUSAR identified it as one of the three components being potentially susceptible to IASCC, no discussion on core shroud was given in this section. Therefore, the NRC staff requested the licensee to provide a summary of core shroud cracking in the BFN units and identify any plant-specific deviations from BWRVIP-76, Revision 1-A, which could affect the management of IGSCC and IASCC in the core shroud under the EPU condition. The licensee provided, in its letter dated April 14, 2016 (Reference 13), the inspection summary and confirmation of one deviation from BWRVIP-76, Revision 1-A. The staff found from Table 2-1 of BWRVIP-76, Revision 1-A that none of the documented cracking for the three units requires plant-specific evaluations. Further, the deviation will not affect the management of IGSCC and IASCC in the core shroud under EPU conditions because the deviation that was filed for a specific fuel cycle was resolved by a corrective action performed in the outage following the fuel cycle.

Core plate inspection requirements are specified in BWRVIP-25, "BWR Core Plate Inspection and Flaw Evaluation Guidelines" (Reference 102). Section 2.1.3 of PUSAR states, "Analysis of the core plate bolts was conducted as part of the Time Limiting Aging Analysis (TLAA) for the Browns Ferry license renewal, per Reference 25." NEDE-33632P, "Browns Ferry (Units 1-3) Core Plate Bolt Analysis Stress Analysis Report," May 2013 (Reference 104) is Reference 25 of PUSAR. The NRC staff requested the licensee to provide a brief summary of NEDC-33632P and explain how the core plate bolt issue during the period of extended operation under EPU conditions is resolved. The licensee, in its response dated April 14, 2016 (Reference 13), indicated that BFN core plate bolts can withstand normal, upset, emergency, and faulted loads considering the effects of stress relaxation on the bolts until the end of the 60-year period of extended operation. This includes consideration of the fluence effects under EPU conditions.

In addition to the inspections outlined above, BFN, Units 1, 2, and 3 utilize hydrogen water chemistry and noble metals applications to mitigate the potential for IGSCC and IASCC in

RVI components. The applicant confirmed that water chemistry conditions are maintained consistent with the EPRI and established industry guidelines. Specific BWRVIP reports documenting these guidelines are mentioned in Section 2.1.4, "Reactor Coolant Pressure Boundary Materials," of the PUSAR: BWRVIP-190, "BWR Water Chemistry Guidelines" (Reference 105); BWRVIP-118, "NMCA [Noble Metal Chemical Application] Experience Report and Applications Guidelines" (Reference 106); BWRVIP-159, "HWC [Hydrogen Water Chemistry]/NMCA Experience Report and NMCA Applications Guidelines" (Reference 107); and BWRVIP-219, "Technical Basis for On-Line NobleChem™ Mitigation and Effectiveness Criteria for Inspection Relief" (Reference 108).

The NRC staff also reviewed TVA's responses to a series of GEH Safety Communications (SCs) related to RVI loading that may be applicable to the BFN units: SC 11-07, "Impact of Inertial Loading and Potential New Load Combination from Recirculation Suction Line Break Acoustic Loads" (Reference 109); SC 12-20, "Error in Method of Characteristics Boundary Conditions Affecting Acoustic Loads Analyses" (Reference 110); and SC 13-08, "Shroud Support Plate-to-Vessel Evaluation for AC [Acoustic] Loads" (Reference 111). The NRC staff requested that TVA assess the impact to RVI integrity under EPU conditions considering these GEH SCs. For SC 11-07, the licensee, in its letter dated April 14, 2016 (Reference 13), responded that the BFN design and licensing basis does not include the application of annulus pressurization loads in the structural evaluation of the RPV and the reactor internals. Further, BFN is not a "new loads" plant as described in the SC. Therefore, the new load combination (acoustic + annulus pressurization) is not applicable to BFN. The NRC staff considers this clarification straightforward and acceptable. For SC 12-20, the licensee stated, in Section 2.2.3.2.1 of the PUSAR, that the acoustic and flow-induced loads following a postulated recirculation line break were evaluated using Transient Reactor Analysis Calculation GE models, not the Method of Characteristics models that prompted the concern of SC 12-20. Therefore, BFN is unaffected by SC 12-20. The NRC staff considers this clarification straightforward and acceptable. For SC 13-08, the licensee stated that the BFN RPV structural evaluation for the shroud support (shroud-to-RPV connection) did incorporate the acoustic loads that were omitted in some other plants. Therefore, the NRC staff determined that the licensee clarified that BFN is unaffected by SC 13-08.

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 BFN, Units 1, 2, and 3. Implementation of the inspection program described above reasonably assures the timely identification of any degradation of RVI components after implementation of the EPU, and 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 BFN, Units 1, 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 in the reactor. The NRC staff's review of RCPB materials covered their specifications, compatibility with the reactor coolant, fabrication and processing, susceptibility to degradation, and degradation management programs. The NRC staff's acceptance criteria for RCPB materials are based on (1) 10 CFR 50.55a and 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 shall be designed, fabricated, and erected to quality standards that reflect the importance of the safety function to be performed; (2) draft GDC-2, insofar as 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 shall be designed, fabricated, and erected to performance standards that will enable the facility to withstand, without loss of the capability to protect the public, the additional forces that might be imposed by natural phenomena such as earthquakes, tornadoes, flooding conditions, winds, ice, and other local site effects; (3) 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; (4) 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 (5) 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 primary water stress-corrosion cracking (PWSCC) of dissimilar metal welds and associated inspection programs is contained in GL 97-01 (Reference 112), Information Notice (IN) 00-17 (Reference 113), Bulletin (BL) 01-01 (Reference 114), BL 02-01 (Reference 115), and BL 02-02 (Reference 116). Additional review guidance for thermal embrittlement of cast austenitic stainless steel components is contained in a letter from C. Grimes, NRC, to D. Walters, Nuclear Energy Institute (NEI), dated May 19, 2000 (Reference 117).

RCPB Materials are described in BFN UFSAR Sections 4.2, "Reactor Vessel and Appurtenances Mechanical Design," and 4.3, "Reactor Recirculation System." BFN's systems and components have also been evaluated for license renewal. The license renewal evaluation associated with RCPB is documented in NUREG-1843 (Reference 76), Sections 2.3.1 and 4.3.

Technical Evaluation

This technical evaluation will consider 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 BFN units. Changes in operating

conditions are specific to the plant. For the purposes of this evaluation, identified modes of degradation are those described in the GALL Report (NUREG 1801, Revision 2 (Reference 80)). 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 in Sections 2.1.6 and 2.2.6.3 of this SE. Potential modes of degradation that 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. On page 2-12 of the PUSAR, the licensee indicates that the EPU will not result in a significant change to the temperature and flow conditions for the RCPB piping. The NRC staff acknowledges the concept that, while peak temperatures in the system do not change, changes in flow rate will cause minor changes in downstream temperatures. The significance of those changes are considered in the paragraphs below.

Identified Modes of Degradation - Intergranular Stress Corrosion Cracking (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 that 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 function due to IGSCC is provided through an inspection program contained in the ASME Code, Section XI and augmented by BWRVIP 75-A (Reference 118). This inspection program depends on the precise construction materials 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 that 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 function of reactor coolant pressure boundary will be maintained, the 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 EPU. Given that the maximum system temperature will not increase as a result of the EPU, the staff finds that the inspection program outlined in ASME Section XI / BWRVIP 75-A will be adequate following the implementation of the uprate. 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 "insignificant variations in temperature" to which the licensee refers, whether positive or negative is not of concern, 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 by use of IGSCC-resistant replacement material, applied weld stress improvement, and having reduced the oxidizing environment with hydrogen water chemistry.

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 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, this material degradation mode as a result of the power uprate is not of a concern.

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 reactor coolant pressure boundary. The threshold for IASCC is generally considered to be approximately 5×10^{20} n/cm^2. The NRC staff finds that no reactor coolant 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 also a well-documented degradation process. 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 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, minor temperature variation between existing and EPU conditions, irrespective of whether these variations are positive or negative is not of concern, 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 that will not result in transgranular cracking. Based on the licensee's current adherence to the EPRI water chemistry guidelines and no modification to the plant's water chemistry as a result of the EPU, this material degradation mode is not of concern.

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). In the present case, 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 draft GDC-1, 2, and 9, final GDC-31, 10 CFR Part 50, Appendix G, and 10 CFR 50.55a. Therefore, the NRC staff finds the proposed EPU acceptable with respect to RCPB materials.

2.1.5 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 contamination by radionuclides. Coatings also provide wear protection during plant operation and maintenance activities. The staff's review covered protective coating systems used inside the containment (Service Level I coatings) for their suitability and stability under design basis loss-of-coolant accident (DBLOCA) conditions, considering temperature, radiation and pressure. The NRC 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 1 (Reference 119), "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, "Protective Coating Systems (Paints) – Organic Materials Review Responsibilities."

The licensee stated, in PUSAR, Section 2.1.5, that the BFN licensing basis regarding coatings is described in the TVA letter to the NRC, "Browns Ferry Nuclear Plant (BFN), Sequoyah Nuclear Plant (SQN), and Watts Bar Nuclear Plant (WBN), 120-Day Response Generic Letter (GL) 98-04 (Reference 120), 'Potential for Degradation of the ECCS and the Containment Spray System (CSS) After a Loss-of-Coolant Accident (LOCA) Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment,' Dated July 14, 1998," dated November 10, 1998 (Reference 121).

Technical Evaluation

The licensee uses engineering procedure, "Technical and Programmatic Requirements for the Protective Coating Program for TVA Nuclear Plants," Revision 20, to implement Regulatory requirements such as 10 CFR Part 50 Appendix B, and guidance such as Regulatory Guide (RG) 1.54, GL 98-04, NUREG-1801, and Information Notices. In addition, the same procedure is used to implement industry and plant-specific guidance such as American Society for Testing and Materials (ASTM) Standards (i.e., D5144, D3843), American National Standards Institute (ANSI) 5.12, EPRI 1003102, and the TVA Nuclear Quality Assurance Manual.

The licensee stated that all Service Level I coatings used at BFN are qualified for Design Basis Accident (DBA) conditions of temperature, pressure, radiation and chemical effects which bound worst case conditions at EPU operating levels. The Service Level I coatings are subject to guidance in RG 1.54, June 1973 (Reference 119), ANSI N101.2-1972 (Reference 122), and ANSI N101.4-1972 (Reference 123). In addition, the licensee stated that the qualification testing and repair/replacement activities meet the applicable requirements provided in the aforementioned standards and regulatory commitments.

The licensee stated that the accumulated gamma dose for the DBA LOCA at EPU conditions is 1.5×10^8 radiation absorbed dose (rad) and is bounded by the Service Level I coating qualification of 1.0×10^9 rad. The peak drywell pressure and temperature under EPU conditions was determined to be 50.9 psig and 336.9 degrees Fahrenheit (°F), respectively. These values are bounded by the Service Level I qualification pressure and temperatures levels of 70 psig and 340 °F, respectively. The licensee indicated that the chemical constituency of the primary containment post-LOCA does not change as a result of the EPU.

The licensee employs a coating monitoring program, which governs inspection of containment coatings in accordance with plant procedures. Inspections are performed each refueling outage and failed or damaged coating is identified and documented. Some examples of coating conditions that are monitored include cracking, blistering, flaking, scaling, peeling, rust through, tiger striping, discoloration, embrittlement or mechanical damage. The licensee stated that any failed coating or damaged coating is remediated in accordance with plant procedures. The licensee further indicated that the condition assessments and resulting repair, replacement, or removal activities ensure that coating subject to detachment from the substrate, which could potentially impact the safe operation of ECCS operation, is minimized.

Furthermore, the licensee stated that the inspection of coating in the immersion zone of the torus is performed in conjunction with desludging of the torus. The frequency of inspection of the immersion zone typically occurs every second or third refueling outage.

The licensee stated that uncontrolled coatings are identified and tracked to ensure that the amount is maintained below the established limit of 157 square feet (ft^2). The uncontrolled coatings limit is a basis for the design of the replacement ECCS suction strainers installed in the BFN. The staff notes that uncontrolled coatings have the potential to affect the performance of the ECCS.

The NRC staff has reviewed the licensee's evaluation in the LAR and the BFN UFSAR, and has confirmed that the applicable regulatory guidance was followed. The NRC staff finds there is 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 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 potential changes 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 their 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, and SRP Section 6.1.2. 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 occurring in carbon steel components exposed to single-phase or two-phase water flow. Components made from stainless steel are immune to FAC, and FAC is significantly reduced in components containing small amounts of chromium or molybdenum. The rates of material loss due to FAC depend on flow velocity, component geometry, fluid temperature, steam quality, oxygen content, and pH. During plant operation, flexibility to control these parameters to minimize FAC is limited. Loss of material by FAC will, therefore, occur. The NRC staff has reviewed the effects of the proposed EPU on FAC and the adequacy of the licensee's FAC program. The intent of the FAC program is to predict the rate of loss so that repair or replacement of damaged components can be made before they reach critical thickness. The licensee's FAC program is based on NRC Bulletin 87-01, "Thinning Pipe Walls in Nuclear Power Plants" (Reference 124), NUREG-1344, "Erosion/Corrosion-Induced Pipe Wall Thinning in U.S. Nuclear Power Plants," April 1989 (Reference 125), and NRC GL 89-08, "Erosion/Corrosion - Induced Pipe Wall Thinning," May 1989 (Reference 126). 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 uses a FAC program to monitor and control FAC. In addition to the generic communications and technical report listed above, the licensee stated that the BFN FAC program is based on guidelines in EPRI Report NSAC-202L-R4, "Recommendations for an Effective Flow-Accelerated Corrosion Program," November 2014 (Reference 127). It consists of predicting loss of material using the CHECWORKS™ Steam/Feedwater Application (SFA) computer code, visual inspection, and volumetric examination of the affected components. The scope of the program includes small and large bore piping systems.

The licensee stated that the proposed EPU implementation will affect system water and steam flow rates. These factors are instrumental in impacting FAC susceptibility and wear rates. 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 no lines that were previously non-susceptible to FAC will become susceptible due to EPU operating conditions.

The choice of the method for detecting and evaluating the effect of FAC on a component is dependent on the type of component and its history. The licensee stated that evaluations provide information on whether components will remain above minimum allowable wall thickness throughout the next operating cycle and what the predicted minimum wall thickness will be at the end of the operating cycle. Additionally, the licensee stated that the evaluation shows the remaining service life of the component and the next scheduled inspection outage.

The licensee stated that FAC susceptible piping can be divided into two categories: lines that meet the requirements to be modeled using CHECWORKS™ SFA, and those that do not. The CHECWORKS™ SFA model is based on plant-specific information and provides quantitative estimates of FAC rates and times available before reaching minimum wall thickness. Inputs to the model include plant operating parameters, inspection results, component material and design features. Additionally, the BFN FAC program utilizes industry experience, BFN plant-specific experience, trending data, and engineering judgment from plant engineers in determining components for inspection.

The licensee stated that the BFN CHECWORKS™ SFA predictive model was updated to reflect plant operating conditions at EPU temperatures, pressures, and flow velocities. Additionally, the licensee provided tables comparing the wear rate of FAC susceptible components before and after implementation of the proposed EPU. The tables provide expected values for temperature, velocity, oxygen and quality parameters for EPU operating conditions. The maximum corrosion rate increase predicted due to the proposed EPU operating conditions was 19.35 percent and is located in the extraction steam line 2 of Unit 2. The staff reviewed the parameters and predicted changes provided in the tables and determined that the corrosion rate increases are reasonable for the corresponding changes in operating conditions. Additionally, the licensee provided a sample list of components for which wall thinning is 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™ SFA program. The changes in wear rate predicted in some of the lines is within the current program's predictive capabilities. The existing FAC program will incorporate all parameter changes associated with the proposed uprate conditions. The staff reviewed the data and finds that the CHECWORKS™ SFA program provides adequate conservatism 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 BFN 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. Furthermore, the staff has determined that the proposed EPU could cause an increase of FAC in some plant systems. However, the staff finds that the 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 staff 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 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 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 reactor coolant pressure boundary (RCPB). The staff's review of the RWCU system included component design parameters for flow, temperature, pressure, heat removal capability, impurity removal capability; and the instrumentation and process controls for proper system operation and isolation. The staff has reviewed the safety-related functional performance characteristics of RWCU system components. The NRC's acceptance criteria for the RWCU system are based on (1) 10 CFR Part 50 Appendix A General Design Criterion 14 (GDC-14), "Reactor Coolant Pressure Boundary," as it requires that the RCPB be designed, fabricated, erected, and tested to have an extremely low probability of rapidly propagating fracture; (2) GDC-60, "Control of Releases of Radioactive Materials to the Environment," as it requires that the plant design include means to control the release of radioactive effluents; and (3) GDC-61, "Fuel Storage and Handling and Radioactivity Control," as it requires systems that contain radioactivity to be designed with appropriate confinement. Specific review criteria are contained in SRP Section 5.4.8, "Reactor Water Cleanup System (BWR)."

Browns Ferry Nuclear Plant is licensed to principal design criteria that predate the GDC found in 10 CFR Part 50, Appendix A (final GDC). The licensee performed a comparative evaluation of the BFN principal design criteria and the AEC proposed GDC published in 1967. The BFN UFSAR, Appendix A, "Conformance to AEC (NRC) Criteria," contains this comparative evaluation. Associated with each of the AEC proposed GDC (draft GDC) is a list of references to locations in the BFN UFSAR where there is subject matter relating to the intent of that particular criteria. As such, the licensee stated that draft GDC-9, 34, 51 and 70; which correspond to specified areas of the BFN UFSAR, meet the requirements of final GDC-14, 60, and 61.

Technical Evaluation

The licensee stated, in PUSAR (Reference 37), Section 2.1.7 that the RWCU system will operate at a slightly decreased temperature (from 530.5 °F to 529.3 °F) at the proposed EPU operating conditions. The RWCU system is usually selected to be approximately 1 percent of feedwater flow; however, the licensee stated that the RWCU system was analyzed for flow at 133,300 pound mass per hour (lbm/hr) at EPU conditions. This flow rate is approximately 0.81 percent 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, but 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 because of the negligible increase to the RWCU system discharge 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 flowrate at the EPU power level, three key reactor coolant chemistry parameters are expected to increase. The licensee indicated that sulfate concentrations will increase from 1.29 part per billion (ppb) to 1.50 ppb. This value is below the administrative goal and action level of 2.0 ppb and 5.0 ppb for sulfates, respectively. The chlorides concentration is expected to increase from 0.33 ppb to 0.38 ppb. This value is below the administrative goal and action level of 1.0 ppb and 5.0 ppb for chlorides, respectively. The reactor water conductivity is expected to increase from 0.121 micro-siemens/centimeter (µS/cm) to 0.132 µS/cm. This value is below the administrative limit and action level of 0.14 µS/cm and 0.30 µS/cm for conductivity, respectively. The staff reviewed the estimated increase in these parameters and determined that there is sufficient operating margin remaining before each parameter's administrative limit and action level are challenged under the proposed EPU conditions.

The staff reviewed the licensee's evaluation and licensing basis documents associated with 10 CFR Part 50, Appendix A, GDC-14, 60, and 61; and confirmed that applicable acceptance criteria were reviewed and found to be acceptable. The licensee demonstrated that the RWCU system will continue to maintain adequate reactor coolant system inventory and water chemistry. The staff reviewed the licensee's evaluation and determined that the proposed EPU will introduce only insignificant changes in the RWCU operating parameters, which will not affect satisfactory performance of its intended functions. The staff finds that the RWCU system will continue to meet system design requirements and that no new design transients will be created at EPU conditions.

Conclusion

The NRC staff reviewed the licensee's evaluation of the effects of the proposed EPU on the RWCU system and concludes that the licensee adequately addressed changes to the reactor coolant and its effects on the RWCU system. The staff further concludes that the licensee has demonstrated that the RWCU system performance characteristics will continue to be acceptable following implementation of the proposed EPU. Specifically, the RWCU system will continue to meet the BFN licensing basis requirements of draft GDC-9, 34, 51, and 70 that correspond to

final GDC-14, 60, and 61. Therefore, the staff finds the proposed EPU acceptable with respect to the RWCU system.

2.1.8 Additional Materials and Chemical Engineering Review Areas

2.1.8.1 Standby Liquid Control System (Regarding pH Control)

This portion of the SE input pertains to the SLCS ability to control suppression pool pH following a LOCA. See Section 2.9.2.1 of this SE for the LOCA radiological analysis relating to the SLCS.

Regulatory Evaluation

The SLCS is credited in the Browns Ferry radiological dose analysis for a LOCA to provide a buffering agent (sodium pentaborate) to the suppression pool water. The use of a buffering agent is needed to ensure that the suppression pool pH remains above 7.0 under worst case conditions for 30 days following a LOCA.

Technical Evaluation

According to NUREG-1465 (Reference 128), "Accident Source Terms for Light-Water Nuclear Power Plants," iodine released from the damaged core to the containment after a LOCA is composed of 95 percent cesium iodide which is a highly ionized salt, soluble in water. Iodine in this form does not present any radiological problems since it remains dissolved in the sump water and does not enter the containment atmosphere. However, in the radiation field existing in the containment, some of this iodine could be transformed from the ionic to the elemental form, which is scarcely soluble in water and can be, therefore, released to the containment atmosphere. Conversion of iodine to the elemental form depends on several parameters, of which pH is very important. Maintaining pH basic in the sump water will ensure that this conversion will be minimized. The pH of the sump water at Browns Ferry is controlled by injection of sodium pentaborate via the SLCS.

The proposed changes to TS 3.1.7 include an increase in SLCS B-10 enrichment, an increase in the credited SLC storage tank boron concentration, and an increase in the credited SLC flow rate. The NRC staff evaluated the impact of these changes, as well as the resulting decrease in peak suppression pool temperature, on suppression pool pH. The staff determined that the proposed changes for EPU will not impact the existing pH analysis, and the pH will remain greater than 7.0 for 30 days following a LOCA.

Conclusion

The NRC staff reviewed the licensee's analyses related to the effects of the proposed EPU on the SLCS and concludes that the licensee adequately accounted for the effects of the proposed EPU on the system and demonstrated that the system will continue to provide the function of post-LOCA pH control following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the post-LOCA suppression pool pH control function of the SLCS.

2.1.8.2 Neutron Absorber Monitoring Program

Regulatory Evaluation

The credited neutron absorber material installed in spent fuel pool (SFP) storage racks ensures that the effective multiplication factor (k_{eff}) does not exceed the values and assumptions used in the nuclear criticality safety (NCS) analyses of record and other licensing basis documents. Neutron absorber materials utilized in SFP storage racks exposed to treated water or treated borated water may be susceptible to reduction of neutron-absorbing capacity, changes in dimension that increase k_{eff}, and loss of material. A monitoring program is implemented to ensure that degradation of the neutron-absorbing material used in SFPs, which could compromise the NCS analyses of record, will be detected. The NRC's acceptance criteria for neutron-absorbing monitoring programs are based on 10 CFR 50.68(b)(4), which states:

> If no credit for soluble boron is taken, the k_{eff} [k-effective] of the spent fuel storage racks loaded with fuel of the maximum fuel assembly reactivity must not exceed 0.95, at a 95 percent probability, 95 percent confidence level, if flooded with unborated water. If credit is taken for soluble boron, the k_{eff} of the spent fuel storage racks loaded with fuel of the maximum fuel assembly reactivity must not exceed 0.95, at a 95 percent probability, 95 percent confidence level, if flooded with borated water, and the k_{eff} must remain below 1.0 (subcritical), at 95 percent probability, 95 percent confidence level, if flooded with unborated water.

Additional requirements are based on final GDC-62, "Prevention of Criticality in Fuel Storage and Handling," as it requires that criticality in the fuel storage and handling system be prevented by physical systems or processes. Specific review criteria are contained in SRP Section 9.1.2, "New and Spent Fuel Storage," Revision 4.

Technical Evaluation

The spent fuel pools (SFPs) at all three BFN units rely on Boral panels to maintain subcriticality. The BFN Unit 3 SFP contains a set of coupons that are used to evaluate the condition of the Boral for all 3 spent fuel pools. All of the Boral panels and coupons were provided by a single supplier and were certified prior to the end of 1983. The Boral material and method of construction for all plates and coupons are considered similar, if not identical, based on Product Quality Certification records.

By letters dated January 28, 2016 (Reference 129), and June 21, 2016 (Reference 130), the NRC staff requested additional information from the licensee regarding the adequacy of the existing coupon surveillance program. The staff questioned the use of the BFN Unit 3 coupons to represent the material in all three units. The staff also questioned the lack of areal density testing in the licensee's coupon surveillance program. By letters dated February 16, 2016 (Reference 6), and July 27, 2016 (Reference 27), the licensee responded to the staff's questions. A summary of the licensee's response to the staff questions is provided below.

The licensee stated that TVA will perform areal density measurements on one Boral sample prior to EPU implementation at the Browns Ferry. In addition, under the EPU amendments, TVA accepted the following license condition for the performance of periodic Boral areal density measurement worded as follows:

> The licensee shall, at least once every ten years, withdraw a neutron absorber coupon from the spent fuel pool and perform boron-10 (B-10) areal density measurement on the coupon. Based on the results of the B-10 areal density measurement, the licensee shall perform any technical evaluations that may be necessary and take appropriate actions using relevant regulatory and licensing processes.

The licensee further stated that upon issuance of the EPU amendments, the current Boral Monitoring Program will be modified accordingly to meet the appropriate license condition.

The NRC staff evaluated the proposed plan to perform an attenuation test prior to EPU implementation as well as the proposed license condition to perform periodic neutron attenuation tests on a frequency that will ensure detection of any material degradation. The staff has determined that the licensee's proposal will provide adequate assurance that any degradation of the Boral material in the SFPs will be identified and mitigated prior to impacting its intended safety function of maintaining subcriticality.

The NRC staff also questioned why the Boral coupons in BFN Unit 3 were representative of the Boral panels in all three spent fuel pools. The staff's inquiries were associated with the spent fuel pool temperatures, water chemistry, time in service, and cumulative dose that each pool's panels or coupons have been exposed to. The licensee's responses are described below.

Water chemistry and temperature are maintained within the limits specified in the BFN Technical Requirements Manual Sections 3.9.2 and 3.9.3. These limits apply to all three pools. The licensee also performed an examination of historical water chemistry and temperature values recorded since the year 2000. There were no excursions in any unit that exceeded the specifications in the Technical Requirements Manual. The staff considers these data adequate to verify that the water chemistry and temperature of the three pools are very similar and the coupons from BFN Unit 3 are representative of the chemistry and temperature experienced by the Boral panels in all three units.

However, with respect to the time in service and the level of radiation exposure experienced by the coupons and the panels, there are some panels that are not bound by the coupons' exposure. Because the re-racking of the pool took place incrementally over more than 20 years, a portion of the total panels were installed prior to the installation of the coupons in 1983. The three BFN SFPs contain a total of 20,940 Boral panels. A total of 1,464 panels pre-date the coupons by approximately 5 years. Another 1908 panels pre-date the coupons by approximately 4 years. Additional panels were installed in the 3 years prior to coupon installation. The result of the licensee not installing the coupons prior to, or in-step with, the first panel installation is that there is a population of panels that have experienced more irradiation and more time in service than the coupons. The licensee stated that TVA will enhance Browns Ferry's neutron absorber monitoring program in order to accelerate the exposure of the coupons. The coupons will be exposed to fresher fuel in an effort to close the gap in exposure between the coupons and the panels that were installed within the 5 years prior to coupon installation.

The ideal scenario for any coupon monitoring program is that the coupons are representative or bounding of the actual in-service materials. In this case there is a population of panels that are not bounded by the coupons in time exposed to the pool environment or in level of irradiation. The staff has evaluated the data presented by the licensee with respect to these unbounded

panels and has considered other aspects of the licensee's neutron absorber monitoring program, which in some ways offset the deficiencies. Favorable aspects of the monitoring program include the following attributes: There is a large amount of favorable operating experience with Boral both at BFN and at other utilities with similar and older Boral. The amount of time that the panels in question exceed the coupon service life is at most slightly over 5 years. The oldest population of pre-coupon panels represents only about 7 percent of the total panel population. The NRC has imposed a license condition to perform areal density testing at an interval not to exceed 10 years. The licensee will perform areal density testing prior to EPU implementation to establish the current Boron-10 areal density of the coupons. The licensee will accelerate the exposure of the coupons in order to reduce the gap in exposure for the unbound panels.

Based on review of the information the licensee provided on the Boral neutron absorber material and the coupon surveillance program, the NRC staff finds that the program provides reasonable assurance that it will be able to detect and monitor indications of loss of material and reduction in neutron-absorbing capacity. This is accomplished by detecting and monitoring the coupon specimen parameters located in the SFP. The NRC staff finds that the 10 year frequency for coupon testing provides reasonable assurance that the Boral will continue to perform its intended function in between surveillances. In addition, performing the proposed testing on the coupons will provide information on the level of B-10 areal density present and material degradation (i.e., loss of material and reduction of neutron-absorbing capacity) of the Boral in the SFP racks.

Conclusion

The NRC staff has reviewed the Boral monitoring program and finds that it provides reasonable assurance with respect to its ability to detect degradation of neutron absorbing material and meet the requirements of 10 CFR 50.68(b)(4), GDC-62, and the guidance in SRP Section 9.1.2. Therefore, the NRC staff finds the coupon surveillance program, as modified by the proposed license condition, acceptable with respect to detecting degradation in the neutron-absorbing material and maintaining the subcriticality requirement in the BFN SFPs.

2.2 Mechanical and Civil Engineering

2.2.1 Pipe Rupture Locations and Associated Dynamic Effects

Regulatory Evaluation

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 insofar as it requires that protection be provided for engineered safety features (ESFs) against the dynamic effects and

missiles 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 Browns Ferry is documented in PUSAR (Reference 37), Section 2.2.1, "Pipe Rupture Locations and Associated Dynamic Effects." NEDC-33004P-A, Revision 4, "Constant Pressure Power Uprate," Class III, July 2003 (CLTR) (Reference 48) was approved by the NRC as an acceptable method for evaluating the effects of EPUs. Section 10.1 of the CLTR addresses the effect of the EPU on high energy line breaks (HELBs).

In the PUSAR, the licensee provided its evaluation of the affected piping systems at EPU conditions and found that no new break or crack locations need to be postulated due to the EPU. 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

Mass and energy (M&E) releases for the intermediate size main steam line break (MSLB) were evaluated and revised to account for the increase in the percent rated steam flow at EPU condition and included the effects that were identified within the potentially reportable condition notification: Error in Main Steam line High Flow Calculational Methodology (Reference 42 of the PUSAR (Reference 131)). The M&E release from the intermediate size MSLB remains bounded by the double-ended break in the main steam valve vault. Also, the M&E releases for the double-ended break in the main steam valve vault at EPU conditions are unchanged from the CLTP analyses. Therefore, the NRC staff found the licensee's evaluation of the MSLB acceptable.

Liquid Line High-Energy Line Breaks

According to the CLTR, the EPU 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 main steam and feedwater flows, which results in an increase in feedwater 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 feedwater systems. The licensee re-evaluated the HELB M&E releases at EPU conditions for the RWCU and feedwater systems as described below.

RWCU System Line Breaks

As stated above, in the CLTR, operation at EPU conditions involves an increase in the steam and feedwater flows, which results in a small increase in downcomer subcooling. This condition results in a small increase in the CLTP RWCU System mass flow rates. As such, the licensee evaluated new M&E releases for the RWCU line for EPU conditions which include the effects of subcooling and the small increase in RWCU discharge pressure. The NRC staff finds that the

structural effects of increased peak pressures are acceptable since the increase in RWCU discharge pressure is small. The effects of increased peak calculated room temperatures in the reactor building resulting from the RWCU line breaks are addressed in the EPU environmental qualification (EQ) analysis. See Section 2.3.1 of the PUSAR for EQ results.

Feedwater System Line Breaks

The licensee indicated, in PUSAR Section 2.2.1, that the associated minor changes in feedwater line break M&E releases are still bounded by the current MSLB M&E releases, which remain unchanged by the EPU. The licensee found that the associated changes in feedwater system line break M&E release will not challenge the bases for the current HELB analysis because the effects of the feedwater line break in the main steam valve vault are bounded by the effects of the postulated MSLB. In addition, the licensee found that the increases in EPU operating temperature and discharge head are bounded by the design temperature and discharge head and associated M&E used in the existing MSLB piping analyses, which remain valid at EPU conditions. Therefore, the NRC staff finds that no new feedwater break locations are required to be postulated for the EPU. The staff notes that since no new feedwater breaks are postulated for the EPU and the M&E releases at existing feedwater postulated breaks are bounded by M&E releases of the main steam line postulated breaks, it is reasonable to conclude that the EPU has no effect on the M&E releases from a HELB in the feedwater piping.

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.

The licensee evaluated the effect of increased feedwater, reactor recirculation system (RRS) and RWCU system pressures for pipe whip and jet impingement. The licensee determined that the EPU feedwater, RRS and RWCU pipe whip and jet impingement loads have negligible effects. For the feedwater and RWCU systems, the increase in maximum operating pressure (1200 psig at EPU conditions) is bounded by the design pressure of 1250 psig used in the current pipe whip and jet impingement design analysis. Therefore, the proposed EPU effects on feedwater and RWCU line breaks pipe whip and jet impingement loads are still bounded by the current licensing basis. The RRS will have a slight increase in operating pressure for EPU conditions; however, this slight increase in pressure remains bounded by the existing margin in the current analysis. As such, the NRC staff finds the proposed EPU acceptable with respect to pipe whip and jet impingement loads resulting from HELBs.

Summary

Based on its review above, the NRC staff finds that there is 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. 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 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 Code, Section III, Division 1, and draft GDC-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) 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 shall be designed, fabricated, and erected to quality standards that reflect the importance of the safety function to be performed; (2) draft GDC-2, insofar as 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 shall be designed, fabricated, and erected to performance standards that will enable the facility to withstand, without loss of the capability to protect the public, the additional forces that might be imposed by natural phenomena such as earthquakes, tornadoes, flooding conditions, winds, ice, and other local site effects; (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; (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; and (5) draft GDC-34 insofar as it requires that the RCPB be designed to minimize the probability of rapidly propagating type failures. Specific review criteria are contained in SRP Sections 3.9.1, 3.9.2, 3.9.3, and 5.2.1.1; and other guidance provided in Matrix 2 of RS-001.

Technical Evaluation

Nuclear Steam Supply System Piping, Components, and Supports

Reactor Coolant Pressure Boundary Piping, Components, and Supports

The RCPB piping consists of a number of safety-related piping subsystems that move fluid through the reactor and other safety systems. The RCPB piping systems that the licensee evaluated for the EPU include the reactor recirculation system (RRS), 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, main steam piping and main steam drain, feedwater piping, the RPV head vent line, and safety relief valve (SRV) discharge piping. In addition, the licensee

addressed branch lines, piping supports, nozzles, penetrations, flanges, and valve connections in its evaluations. The licensee also evaluated the safety-related thermowells and the sample probes in the main steam system, feedwater system, and RRS for flow-induced vibration (FIV) due to increased flows in the main steam system, feedwater system, and RRS resulting from EPU implementation. Section 2.2.2 of the PUSAR indicates that the licensee followed the guidance from the NRC-approved CLTR and that the proposed EPU for BFN meets all CLTR dispositions.

The licensee, in PUSAR (Reference 37) Section 2.2.2, indicated 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 EPUs 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 dispositioned these systems as unaffected by the EPU. As such, the licensee concluded these systems were acceptable for operation at the EPU conditions. The NRC staff finds the licensee's justification of the disposition 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 either no change or insignificant change at EPU conditions.

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

The CLTP analysis of record for the MSL did not include loads due to the turbine stop valve (TSV) closure transient. This transient is considered one of the most significant loads in the qualification of main steam piping and supports for an EPU. As discussed in the PUSAR Section 2.2.2.2.1.2, TSV Closure loads bound the main steam isolation valve (MSIV) closure event loads because the MSIV closure time is significantly longer than the TSV closure time.

The NRC staff notes that an EPU increases the operating pipe support loads due to the feedwater and main steam piping and associated branch piping up to the first anchor or support that experience an increase in the flow, pressure, and/or temperature, resulting in an increase in operating stress and fatigue.

The licensee's evaluations determined that the interface loads on snubbers, struts, guides, and flange connections at EPU conditions are within the design limits of these components. Also, for the RCPB main steam piping outside of containment penetration, the revised TSV closure fluid transient analysis bounds MSL loads. The licensee found that the pipe stresses and support loads for RCPB feedwater inside and outside containment met all ASME Code criteria. Therefore, the NRC staff found that design loads and stresses are bounding at EPU conditions.

Main Steam and Associated Piping System Evaluation

The licensee indicated in the PUSAR, that for Browns Ferry, an increase in flow and mechanical loads was evaluated on a plant-specific basis consistent with the methods specified in Appendix K of ELTR1.

The main steam and associated branch piping inside containment and RCPB piping outside containment were evaluated to the USAS B31.1.0 stress criteria (Reference 132). The SRP Section 3.6.2 criteria are not licensing commitments for Browns Ferry; therefore, all pipe ruptures were postulated in accordance with the current licensing basis.

Moreover, the licensee indicated that because the main steam piping pressures and temperatures are not significantly affected by the EPU, there is no effect on the analyses for these parameters. Seismic inertia loads, seismic building displacement loads, and main steam relief valve (MSRV) discharge loads are not affected by the EPU.

The licensee indicated that a review of the increase in flow associated with the EPU indicates that piping stress changes do not result in stress limits being exceeded for the main steam system and attached branch piping or for RPV nozzles and containment penetrations. The revised design analyses have sufficient margin between calculated stresses and USAS B31.1.0 allowable limits (see Table 2.2-3a) for operation at EPU conditions. The pressure and temperature of the main steam piping are unchanged for the EPU.

Similarly, the branch pipelines (safety relief valve discharge line, reactor core isolation cooling, high pressure coolant injection, RPV head vent, and main steam drains including the MSIV drain) connected to the main steam headers were evaluated to determine the effect of the increased main steam flow on the lines. The licensee concluded that there is no adverse effect on the existing main steam branch line qualifications due to the increased main steam flows resulting from the EPU. As with the main steam piping, the pressures and temperatures for these branch pipelines do not change as a result of the EPU. A review was performed of postulated pipe break locations. The review was conducted in accordance with the requirements of the current licensing basis methodology. As a result of this review, the licensee did not identify any new postulated break locations. Based on existing margins available for the main steam piping, it was concluded that the EPU does not result in reactions in excess of the current design capacity.

The pipe stress analyses of record for RCPB main steam piping outside containment were revised to evaluate the increased TSV closure fluid transient loading with the EPU. The revised analysis for the main steam system outside containment demonstrates that the design has sufficient margin between calculated stresses and the allowable limits in the code of record, USAS B31.1.0 – 1967 to justify operation at EPU conditions. Based on its review of the licensee's evaluations, the NRC staff finds that there is sufficient margin between calculated stresses and the allowable limits.

Pipe Supports

The licensee indicated that a review of the change in flow associated with the EPU indicates that piping load changes do not result in load limits being exceeded for the main steam piping system; therefore, the pipe supports for the main steam piping system are adequate at EPU conditions. The current design analyses were updated for conditions representative of EPU

operation in the main steam piping system as applicable. No inside containment pipe support modifications are required for the EPU.

Main Steam Isolation Valves

The MSIVs are part of the RCPB, and perform the safety function of steam line isolation during certain abnormal events and accidents. The MSIVs must be able to close within a specified time range at all design and operating conditions.

The licensee indicated that the MSIVs have been evaluated, as discussed in Section 4.7 of ELTR2, Supplement 1. The evaluation covers both the effects of the changes to the structural capability of the MSIV to meet pressure boundary requirements, and the potential effects of EPU-related changes to the safety functions of the MSIVs. The generic evaluation from ELTR2 is based on: (1) a 20 percent thermal power increase; (2) an increased operating dome pressure to 1,095 psia; (3) a reactor temperature increase to 556 °F; and (4) steam and feedwater flow increases of about 24 percent. Table 1-2 of ELTR2 (Reference 50) provides the maximum nominal dome pressure and temperature as well as the changes in steam and feedwater flows. From these parameters, it can be determined that the evaluation from ELTR2 as well as the MSIV closure times are applicable to Browns Ferry.

Feedwater System Evaluation

The licensee indicated that the pressure changes are insignificant for the EPU and are bounded by those used in the analysis of record. The calculations of record were revised to reflect the EPU operating temperatures (Table 2.2-5, of the PUSAR). The current licensing basis for the reactor feedwater system inside containment complies with the Browns Ferry code of record stress criteria (Reference 132), for the effect of thermal expansion displacement on the piping snubbers, hangers, and struts. Piping interfaces with RPV nozzles, penetrations, and flanges, remain bounded by the licensing bases analyses.

The NRC staff 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 licensee submitted Revision 1 to the BFN EPU Flow Induced Vibration Analysis and Monitoring Program. The BFN EPU Flow Induced Vibration Analysis and Monitoring Program was revised to correct the acceptance criteria values provided in Tables 3-1 through 3-3, and was updated based on further reviews of the results obtained from the time history analyses described in Section 4.2.1 of the BFN EPU LAR, Attachment 45. The projected percent of acceptance criteria values were also updated as a result of the updates to the acceptance criteria values. The EPU projected vibration remains below the revised acceptance criteria value at all monitoring locations.

The feedwater system and associated branch piping outside containment

The bounding transient considered was for a simultaneous trip of all three feedwater pump turbines that results in transient loading on piping as the feedwater pumps coast down. The results of this analysis showed that the feedwater piping is acceptable for feedwater fluid transients that occur at EPU conditions and that the feedwater piping design has sufficient margin between calculated stresses/loads and the allowable limits in the code of record as shown in Table 2.2-3d in the PUSAR.

Pipe Stresses

The licensee indicated that for feedwater piping inside containment, a review of the changes in operating pressure, temperature and flow associated with the EPU indicates that piping stress changes do not result in stress limits being exceeded for the reactor feedwater piping system, RPV nozzles, and postulated pipe break locations (Table 2.2-3b of the PUSAR)). The current Browns Ferry design analyses were revised for conditions representative of EPU operating modes in the feedwater piping system.

Also included were the RCPB portion of the feedwater piping outside containment. A review of the increase in flow, operating pressure, and temperature associated with EPU indicates that piping load changes do not result in load limits being exceeded for the feedwater piping system and attached branch piping.

No new postulated break locations were identified. The analysis for the feedwater system outside containment demonstrates that the design has sufficient margin between calculated stresses and the allowable limits in the code of record (Reference 132).

Pipe Supports

The feedwater system piping outside containment was evaluated for the effects of the EPU temperature increase on the piping design analyses. It was concluded that the EPU does not have an adverse effect on feedwater pipe support design, and all loads were within limits.

Other Piping Evaluation

The licensee indicated that the nominal operating pressure and temperature of the reactor are not changed by the EPU. Aside from main steam and feedwater, no other system connected to the RCPB experiences a material increase in flow rate at EPU conditions. Only minor changes to fluid conditions are experienced by these systems due to higher steam flow from the reactor and the subsequent change in fluid conditions within the reactor. Additionally, piping dynamic loads due to MSRV discharge at EPU conditions are bounded by those used in the existing analyses.

These systems were previously evaluated for compliance with the code of record stress criteria as required. Because none of these piping systems connected to the RCPB experience any significant change in operating conditions due to the EPU, they are all acceptable as currently designed. Therefore, the BFN EPU meets all CLTR dispositions for RCPB piping.

Balance-of-Plant Piping, Components, and Supports

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

- RHR piping
- CS Piping (outside containment)
- Main steam piping (outside containment)

- Extraction steam piping
- Feedwater piping (outside containment)
- Condensate piping
- Moisture separator drains piping
- Feedwater heater vents and drains piping
- Cross around relief valve discharge piping
- Condensate demineralizer piping (condensate demineralizer modifications)

The licensee stated, in the PUSAR, that for the EPU affected safety related piping and piping which is required to withstand a seismic event, the 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 feedwater piping, the licensee indicated that design basis loads used in the CLTP current analysis of record bound piping loads at EPU conditions. Therefore, the feedwater piping remains structurally adequate at the EPU conditions.

The licensee stated that for main steam piping outside containment, a new pipe stress analysis was performed to evaluate the increased TSV closure fluid transient loading with the EPU. Detailed TSV closure fluid transient forcing functions were developed and the piping stress analysis was evaluated at EPU conditions to determine loads following the EPU due to the TSV closure transient. The EPU main steam analysis resulted in main steam piping outside containment meeting all code of record criteria (Reference 132), the pipe stress results are shown in Table 2.2-4a of the PUSAR. With the implementation of support modifications as described in the EPU LAR (Reference 1), Attachment 47, "List and Status of Plant Modifications," the revised analysis for the main steam system outside containment demonstrates that the design has sufficient margin between calculated stresses and the allowable limits in the Browns Ferry code of record to justify operation at the EPU conditions.

The PUSAR notes that the main steam and feedwater piping have increased flow rates and flow velocities in order to accommodate the EPU. As a result, the main steam and feedwater 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 BFN during power ascension to confirm acceptable vibration levels at EPU power. This program addresses systems impacted by the EPU and identifies locations on those systems where monitoring equipment will be installed. The licensee in Attachment 45, "Flow Induced Vibration Analysis and Monitoring Program," to the EPU LAR, provides additional information for the EPU vibration monitoring program which, in addition to feedwater and main steam, 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 NRC staff 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 Supports 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 BFN. 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 the 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, Section 2.6.1.2.1. 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.

The licensee noted that the suppression pool (SP) temperature response for large and small break LOCAs and other events is evaluated in Section 2.6 of the PUSAR and is reported in Table 2.6-1, of the PUSAR. The peak suppression pool temperatures for these events at EPU conditions are bounded by the current design analyses of the torus attached piping where the piping was analyzed at a conservatively high peak temperature of 187.3 °F. With the implementation of support modifications to reinforce an existing pad at an ECCS ring header branch connection, as described in EPU LAR Attachment 47, the licensee demonstrated that the design has sufficient stress margin at EPU conditions. The piping dynamic loads due to MSRV discharge at EPU conditions (Section 2.6.1.2.2, of the PUSAR) are bounded by the current design bases.

The licensee stated that the intermediate break accident (IBA) event thermal load in NEDO-21888, Revision 2, GE Nuclear Energy Report, "Mark I Containment Program Unique Load Definition Browns Ferry" (Reference 133), bounds both the EPU small break accident (SBA) and IBA thermal loads. The Browns Ferry design calculations for the torus attached piping shows that the current design calculations conservatively used the GE Nuclear Report thermal loads from the IBA event (based on a suppression pool temperature of 158 °F) for load combinations that required hydrodynamic loading in the SBA and IBA analysis. Other SBA/IBA containment hydrodynamic loads/load combinations at EPU conditions are either unchanged or bounded by the loads/load combinations used in the current design analyses of the torus attached piping. The load conditions for the torus attached piping are either unchanged for the EPU or bounded by the loads used in the Browns Ferry current analysis of record.

Other BOP Piping Systems

The licensee indicated in the PUSAR that existing piping design analyses were performed at pressures and temperatures that bound EPU conditions for some systems. The remaining piping design analyses have sufficient margin to accommodate the small increases in pressure or temperature following the EPU and still meet ASME Code allowables. The evaluations (see Tables 2.2-4b through 2.2-4f and 2.2-5, of the PUSAR) show that for all systems, design margins for piping, supports and equipment nozzles are either unaffected or are adequate to accommodate the increased loads and movements resulting from the EPU.

The NRC staff has determined that for BOP systems that do not require a detailed analysis, pipe routing and flexibility are considered to remain acceptable for the EPU. These are non-safety-related BOP systems for which no piping or support analyses are documented. For

systems that remain cold (less than 200 °F), the thermal stresses and displacements are not significant. Moreover these systems have adequate flexibility, and any increase in the operating temperature range following the EPU is not significant.

Reactor Vessel and Supports

The licensee indicated that the fatigue of plant-specific components is monitored pursuant to license renewal requirements (Reference 76) and those components are: [[

]] These components have been reviewed by the licensee to ensure the fatigue usage factor for a 60 year life is less than the ASME code limit of 1.0 as presented in Table 2.2-6 of the PUSAR.

[[

]] The evaluation results are presented in Table 2.2-6.

[[

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[[ ]]
[[ ]]
[[ ]]
[[ ]]

The evaluation results for those components in the table above are presented in Table 2.2-6 of the PUSAR.

The high and low pressure seal leak detection nozzles have been reviewed and found acceptable for 60-year EPU conditions.

The effect of the EPU was evaluated to ensure that the reactor vessel components continue to comply with the existing structural requirements of the ASME Code.

- 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 (Units 1, 2 and 3).

- Recirculation Inlet Nozzle: This component was modified and the governing Code for the modification is the ASME Boiler and Pressure Vessel Code, Section III, 1980 Edition with Addenda to and including Winter 1981 (Units 1, 2 and 3).

- Recirculation Outlet Nozzle: This component was modified and the governing Code for the modification is the ASME Boiler and Pressure Vessel Code, Section III, 1980 Edition with Addenda to and including Winter 1981 (Units 1, 2 and 3).

- Core Spray 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 (Units 1, 2 and 3).

- CRD Hydraulic System Return Nozzle Cap: This component was newly installed and the governing Code for the modification is the ASME Code, Section III, 1974 Edition with Addenda to and including Summer 1976 (Units 1, 2 and 3).

- Jet Pump Instrumentation Seal Safe End: This component was modified and the governing Codes for the modification are the ASME Code, Section III, 1980 Edition with Addenda to and including Winter 1981 (Units 1 and 2) and the ASME Code, Section III, 1986 Edition (Unit 3).

Design Conditions

The licensee indicated that because there are no changes in the design conditions due to the EPU, the design stresses are unchanged and the Code requirements are met.

Normal and Upset Conditions

The Browns Ferry fatigue analysis results for the limiting components are provided in Table 2.2-6 of the PUSAR. The plant- specific evaluations were performed with environmental fatigue using NUREG/CR-6909 (Reference 134) for the fatigue life correction factor to the ASME fatigue analyses. This was done to support Browns Ferry license renewal (Reference 76).

Emergency and Faulted Conditions

The licensee indicated that, the stresses due to emergency and faulted conditions are based on loads such as peak dome pressure, which are unchanged for the EPU. Therefore, Code requirements are met for all RPV components under emergency and faulted conditions, and the reactor vessel meets all EPU dispositions.

Control Rod Drive Mechanism

No change in operating condition. The CRD mechanism is unaffected by the EPU.

Recirculation Pumps and Supports

No change in operating condition. The recirculation pumps and supports are unaffected by the EPU.

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 draft GDC-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 Support

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) 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, tested, and inspected to quality standards that reflect the importance of the safety function to be performed; (2) draft GDC-2, insofar as 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 shall be designed, fabricated, and erected to performance standards that will enable the facility to withstand, without loss of the capability to protect the public, the additional forces that might be imposed by natural phenomena such as earthquakes, tornadoes, flooding conditions, winds, ice, and other local site effects; (3) draft GDC-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 loss of coolant accident; and (4) 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 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 the 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 was performed. If the loads increase due to the EPU, then the effect of the load increase was evaluated further and new stresses were determined by linearly scaling up the existing design basis stresses in proportion to the loads. The resulting stresses were 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 NEDC-33004P-A, Revision 4, "Constant Pressure Power Uprate," Class III, July 2003 (Reference 48), which was approved by the NRC as an acceptable method for evaluating the effects of EPUs. Sections 3.3 and 3.4 of the CLTR address the effect of an EPU on Reactor Vessel and Reactor Internals, respectively.

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 CUFs from the evaluation results for the RPV internals are summarized on PUSAR in Section 2.2.3. All stresses and CUFs are shown to be within design basis allowable limits and, therefore, are acceptable.

The flow induced vibration (FIV) assessment of the RPV internals for the EPU is contained in PUSAR, Section 2.2.3.1.2. As stated in 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:

- Control Rod Guide Tube (CRGT)
- In Core Guide Tubes (ICGT)
- Feedwater Spargers
- Jet Pumps (JP)
- Jet Pump Sensing Lines (JPSL)
- Shroud
- Shroud Head and Separator Assembly
- Core Spray Piping Line and Sparger
- Fuel Assembly
- Guide Rod

- Shroud Head Bolts
- Top Guide
- Head Spare Instrument Nozzle
- Top Head Instrument Nozzle
- Top Head Vent Nozzle
- Steam line Nozzle
- Water Level Instrument Nozzle

The licensee stated that the results of the vibration evaluation show that continuous operation at a reactor power of 102 percent of 3952 MWt and 105 percent of rated core flow does not result in any detrimental effects on the critical or safety-related reactor internal components shown above. Flow induced vibration of critical reactor internal components at EPU is predicted based on the available startup test data at [[

]] Vibration amplitudes are also adjusted by a [[

]] The extrapolated vibration amplitude response under EPU conditions is compared with the acceptance criterion in the percent criteria for each mode. The percentages of the criteria for all modes are cumulative as total percent criteria. [[

]]

Reactor Internal Pressure Differences

The EPU results in higher pressure differences across the RPV internals due to higher core exit steam flow. The licensee calculated the RIPDs for normal, upset, and faulted conditions.

Tables 2.2-7 through 2.2-9 of the PUSAR compare the RIPDs across the major reactor internal components during current and EPU operation in the normal, upset, and faulted conditions, respectively. The EPU RIPDs are performed with a full core of GE13 fuel. The RIPDs for GE13 fuel are bounding for GE14 fuel. This is due to the higher flow resistance and resultant higher pressure drop of the GE13 fuel bundle. The EPU RIPDs are also applicable to GE13, GE14, ATRIUM-10, and ATRIUM 10XM fuel types.

The licensee stated that the acoustic and flow-induced loads following a postulated recirculation line break were also evaluated using TRACG models. The methodology for determining the Browns Ferry acoustic and flow-induced loads at EPU rated thermal power is unchanged from that used for current rated thermal power and is unaffected by the issue identified in GEH Safety Communication (SC) 12-20 (Reference 50 , of the PUSAR)). The acoustic and flow-induced

loads associated with the extension of the Maximum Extended Load Line Limit Analysis (MELLLA) and Increased Core Flow (ICF) domain to include EPU operation are bounded by the acoustic and flow-induced loads associated with reduced feedwater temperature operation at the minimum pump speed point on the MELLLA line (Point "C" of Figure 1-1 of the PUSAR).

Reactor Internals Structural Evaluation (Non-FIV)

The loads considered in the EPU structural evaluation of the internals include: dead weight, RIPDs, seismic loads, thermal loads, flow loads, and acoustic and flow-induced loads due to a recirculation line break, consistent with the design basis. [[

]]

The RPV internals consist of the core support structure components and non-core support structure components. The requirements of the ASME Code are used as a guideline in their evaluation. The reactor internal components evaluated are:

Core Support Components

- Shroud
- Shroud Support
- Core Plate
- Top Guide
- Control Rod Drive Housing (CRDH)
- Control Rod Guide Tube (CRGT)
- Orificed Fuel Support (OFS)
- Fuel Channel

Non-Core Support Components

- Feedwater Sparger
- Jet Pumps
- Core Spray Line and Sparger
- Access Hole Cover (AHC)
- Shroud Head and Steam Separator Assembly
- In-Core Housing and Guide Tube
- Vessel Head Cooling Spray Nozzle

- Jet Pump Instrument Penetration Seal
- Differential Pressure and Standby Liquid Control Line

The licensee indicated that the effects of the thermal-hydraulic changes due to the EPU on the reactor internals were evaluated. All applicable loads and load combinations were considered consistent with the existing design basis analysis. These loads include the RIPDs (Section 2.2.3.2.1 of the PUSAR), dead weight, seismic loads, acoustic and flow induced loads, scram and thermal loads.

EPU loads are compared to those used in the existing design basis analysis. The method of analysis is to linearly scale the critical/governing stresses based on increases in loads as applicable and compare the resulting stresses against the allowable stress limits. Conservative assessment is used.

The NRC staff notes that Table 2.2-10 of the PUSAR presents stresses for the reactor internal components as affected by EPU. The NRC staff concludes that all stresses are within the design basis ASME Code allowable limits, and the RPV internal components are demonstrated to be structurally qualified for operation at EPU conditions.

Conclusion

The NRC staff has reviewed the licensee's evaluations related to the structural integrity of reactor internals and core supports and concludes that the licensee has adequately addressed the effects of the proposed EPU on the reactor internals and core supports. The NRC staff further concludes that the licensee has demonstrated that the reactor internals and core supports will continue to meet the requirements of 10 CFR 50.55a, final GDC-10 and draft GDC-1, 2, 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 staff's review included certain safety-related pumps and valves typically designated as Code Class 1, 2, or 3 under Section III of the American Society of Mechanical Engineer (ASME) *Boiler & Pressure Vessel Code* and within the scope of 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 valves and pumps at BFN. The review also covered any impacts that the proposed EPU might have on the licensee's motor-operated valve (MOV) programs related to GL 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance" (Reference 135); GL 96-05, "Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves" (Reference 136); and GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves" (Reference 137). 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 it requires those systems and components which are essential to the prevention of accidents which could affect the public health and safety or to mitigation of their consequences be designed, fabricated, and erected 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, 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 capability shall be provided for testing functional operability of valves and associated apparatus essential to the containment function for establishing that no failure has occurred and for determining that valve leakage does not exceed 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 (IST) program requirements identified in that section. Specific review criteria are contained in SRP Sections 3.9.3 and 3.9.6, and Power Uprate Review Standard RS-001.

Technical Evaluation

TVA addressed the capability of safety-related pumps and valves at BFN to perform their intended design basis functions under EPU conditions in Section 2.2.4 "Safety-Related Valves and Pumps" of PUSAR (Reference 47). The NRC staff reviewed the licensee's evaluation of the impact of EPU conditions on safety-related valves and pumps at BFN Units 1, 2, and 3. This review is summarized in the following paragraphs.

In NRC Inspection Report (IR) 50-259, 50-260 and 296/98-05 dated September 18, 1998, the NRC staff closed its review of the licensee's program to demonstrate the design basis capability of safety-related MOVs within the scope of GL 89-10 to perform their intended functions at BFN Units 2 and 3. By letter dated March 6, 2007 (Reference 138), the NRC staff also concluded that the GL 89-10 program at BFN Unit 1 was acceptable because the program was the same as that of the program at BFN Units 2 and 3. In its letter dated November 19, 1999 (Reference 139), the NRC staff determined that in response to GL 96-05, TVA established an acceptable program for BFN Units 1, 2, and 3 to periodically verify the design basis capability of safety-related MOVs. By letter dated June 23, 1999 (Reference 140) for BFN Units 2 and 3, and letter dated January 28, 2005, for BFN Unit 1 (Reference 141), NRC staff concluded that TVA had adequately addressed the issues related to pressure locking and thermal binding of GL 95-07.

In its request for the EPU license amendment, the licensee stated that the existing calculations for GL 89-10 MOVs were reviewed and the review shows that the maximum ambient temperatures used in existing MOV calculations bound the maximum ambient temperatures for the EPU with the exception of one Unit 3 MOV, 3-FCV-75-53, but this slight temperature increase has no effect on the affected valve capability or margin. Other parameters such as valve differential pressure/line pressure, motor terminal voltage, pressure locking and thermal binding, and valve stroke time effect were evaluated and were found to be either unaffected by the EPU or the EPU effect was bounded by the parameters used in the existing calculations of record. The peak containment pressure following a LOCA increases slightly due to the EPU (less than 1.4 psig from the peak pressures used in the existing MOV calculations). MOVs that are required to operate during a LOCA were evaluated for the changes in peak containment pressure and were found to maintain positive thrust/torque margin against the thrust/torque required for the valves to perform their open or close function. Therefore, the NRC staff

concludes that no valves under the BFN GL 89-10 and GL 96-05 program require modification to support EPU implementation, and operation at EPU conditions does not affect the capability of the GL 89-10 MOVs to perform their design basis functions.

Pressure locking and thermal binding had been previously evaluated and found acceptable for all BFN safety-related gate valves. TVA's review indicates that EPU will not cause additional safety-related gate valves to be susceptible to pressure locking or thermal binding, and the EPU will not affect the susceptibility of valves already modified to prevent these problems. Therefore, the EPU has no effect on GL 95-07 for pressure locking or thermal binding of safety-related power-operated gate valves.

TVA has in place an air operated valve (AOV) program (NETP-114). The program has been evaluated for compliance with the Joint Owner's Group air operated valve testing requirements and the licensee states that the program will continue to provide assurance that AOVs will be appropriately monitored and maintained during plant operations under EPU conditions.

TVA has in place a corrective action program at BFN. The purpose of the corrective action program is to manage continuous improvement of station and organizational performance through identification, evaluation, correction and prevention of reoccurrence of unwanted and/or unexpected conditions, deviations, events, or issues that have the potential for affecting the safe, reliable, and efficient operation of BFN. Included in the program is recognition of any lessons learned or improvement opportunities identified from plant operating experience.

In its LAR dated September 21, 2015 (Reference 1), the licensee described its review of the IST Program for safety-related pumps and valves at BFN Units 1, 2, and 3 for EPU operations. The Code of Record for BFN, Units 1, 2, and 3 is the 2004 Edition through 2006 Addenda of the ASME OM Code. The IST Program at BFN, Units 1, 2, and 3 assesses the operational readiness of pumps and valves within the scope of the ASME OM Code. The scope of the IST Program at BFN Units 1, 2, and 3, and the testing frequencies will not be affected by the EPU. No changes are anticipated in the IST Program at BFN, Units 1, 2, and 3 in support of the EPU request.

Conclusion

The NRC staff has reviewed the licensee's assessments related to the functional performance of safety-related valves and pumps at BFN Units 1, 2, and 3 in support of the EPU license amendment request. Based on the above described review, the staff has determined that the licensee 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 programs related to GL 89-10, GL 96-05, and GL 95-07, and the lessons learned from those programs to other safety-related, power operated valves. Based on this, the NRC staff has concluded that the licensee has demonstrated that safety-related valves and pumps will continue to meet the requirements of draft GDC-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 with pipe-whip and jet impingement forces. The primary input motions due to the safe shutdown earthquake 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, and erected to quality standards that reflect the importance of the safety functions to be performed; (2) draft GDC-2, insofar as 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 shall be designed, fabricated, and erected to performance standards that will enable the facility to withstand, without loss of the capability to protect the public, the additional forces that might be imposed by natural phenomena such as earthquakes, tornadoes, flooding conditions, winds, ice, and other local site effects; (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 and missiles that might result from plant equipment failures, as well as the effects of a LOCA; (5) 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; (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.

Technical Evaluation

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 Browns Ferry 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 Browns Ferry maintenance rule program that 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.

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

Conclusion

The NRC staff has reviewed the licensee's evaluations of the effects of the proposed EPU on the qualification of mechanical and electrical equipment and concludes that the licensee has: adequately addressed the effects of the proposed EPU on this equipment; and demonstrated that the equipment will continue to meet the requirements of draft GDC-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

Regulatory Evaluation

The steam dryer is a reactor internal component and is located in the steam dome portion of the RPV. The function of the steam dryer is to dry the steam to a very high quality of approximately 99.9 percent (or 0.1 percent moisture carryover), when it exits the dryer. Although 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 to perform their safety functions. The NRC staff's review was focused on the effects of the proposed EPU on the qualification of the steam dryers to withstand seismic events and the dynamic effects associated with flow induced vibration, MSLB, and turbine stop valve closure.

Since the steam dryer is a safety significant component, the NRC's acceptance criteria are based on: (1) 10 CFR 50.55a and final 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) final GDC-2, insofar as it requires that SSCs important to safety be designed to withstand the effects such as earthquakes, and (3) final GDC-4 insofar as it requires that SSCs important to safety be designed to accommodate the effects of normal operation, testing, and postulated accident conditions. Based on a review of Section A.2 of the Browns Ferry UFSAR, it is concluded that the design of the steam dryers of the BFN units meets the intent of GDC-1, GDC-2, and GDC-4.

Specific NRC review criteria are contained in NUREG-0800 (SRP) (Reference 75), Sections 3.9.1, 3.9.2, 3.9.3, and 3.9.5; RG 1.20 (Reference 142), and other guidance provided in Matrix 2 of RS-001 and BWRVIP-182A (Reference 143).

The reactor vessel and internals are described in Sections 3.3, and 4.2 of the BFN 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 license renewal and documented in Section 3 of NUREG-1843 (Reference 76).

Technical Evaluation

Plant operation at EPU conditions can result in adverse flow effects on the main steam system, feedwater 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 (Reference 37) Section 1.2, an increase in electrical output is accomplished by generating and supplying higher steam flow to the turbine generators via the main steam lines. Some plant components, such as the steam dryers, do not perform a safety function but must retain their structural integrity to avoid the generation of loose parts that might adversely impact the capability of other plant equipment to perform 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 TVA of the potential adverse flow effects for the proposed EPU for Browns Ferry including consideration of the design input parameters and the design basis loads and load combinations for the BFN steam dryers 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 BFN steam dryers, and also included a comparison of the resulting stresses against the applicable limits.

As a part of the BFN EPU LAR, the licensee performed quantitative analyses of the Browns Ferry original steam dryers which showed that modifications to enhance structural integrity of the steam dryers were needed for EPU conditions. Rather than modify the existing dryers, TVA made a decision to replace the original steam dryers with the replacement steam dryers (RSDs). TVA plans to instrument the RSD of the lead unit (BFN Unit 3) to subsequently verify the MSL strain gauge data-based predictive analysis results with instrumented dryer data during the first power ascension from CLTP to EPU. The lead unit data will be used to develop BFN-specific limits for the follow-on units (BFN Unit 1 and Unit 2) during their power ascension.

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 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, 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 used the methods consistent with the limitations and restrictions placed on these 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.

2.2.6.2 Steam Dryer Design and Modifications

The original steam dryers at BFN, Units 1, 2, and 3, were GE BWR/4, parallel vane bank slanted hood design steam dryers with perforated plates at the inlet and outlet sides of the vane banks. As part of the EPU implementation, the licensee plans to replace the original GE dryers with parallel vane bank curved hood design dryers for all three Browns Ferry units.

In accordance with RG 1.20 (Reference 142), the BFN RSD for the lead unit is classified as [[ ]]. The BFN RSD is based on a field tested design of a curved hood six-bank RSD used in a BWR/4 reactor that has completed its comprehensive vibration assessment program at EPU conditions. This BWR/4 RSD serves as the valid prototype for the BFN RSD.

In order to maintain the structural integrity at the EPU loading conditions, the BWR/4 RSD design uses thicker plates on the steam dryer such as the skirt panels, hood panels, hood supports and outlet end plates. In addition, the use of fillet welds is minimized. This steam dryer also uses [[ ]] to improve the stress distribution and move the welds away from the stress concentration at these panel junctions. The RSD also uses an [[ ]]. As a result, the baseline BWR/4 prototype RSD design is significantly more robust than the original steam dryer it replaced. Similarly, the RSD design for BFN Units 1, 2, and 3 is more robust than the original steam dryer design.

The RSDs will be supported on four brackets attached to the inside surface of the reactor pressure vessel wall. The brackets support the dryer via its support ring, two seismic blocks, and two jack bolt/latch mechanisms. Attached under the support ring is a skirt, which has vertical drain channels welded to its outside. The upper portion of the steam dryer includes six parallel vane banks of curved hood design. The function of the vane banks which contain the vane bundles is to separate the moisture from the steam flow by letting the steam pass through vane modules inside the vane banks. The vane bundles contain numerous chevron shaped vanes, moisture collection hooks, internal tie rods, and plates. Each vane bank has a hood that leads the steam flow into the vane bank through an inlet perforated plate. The dried steam from the vane banks exits through a perforated plate. The vane banks stand on troughs that collect and lead the excess water through drain pipes and to the drain channels. The perforated plates at the inlet and outlet sides of each vane bank ensure an even flow through the vane banks. The design improvements of the RSDs based on lessons learned contribute to the better performance of the steam dryer as well as increased fatigue margin.

The RSD evaluations submitted by the licensee in the LAR (Reference 1) were based on the plant based load evaluation (PBLE) 02 methodology that uses BFN MSL strain gauge data, and end-to-end bias and uncertainties from benchmarking on the BWR/4 prototype steam dryer. [[ ]] These evaluations will be subsequently validated by an end-to-end benchmark based on PBLE01 methodology that uses

the BFN Unit 3 on-dryer instrument data during first power ascension CLTP of 3458 MWt. to EPU power of 3952 MWt.

The licensee has taken precautions in selecting intergranular stress corrosion cracking (IGSCC)-resistant materials. Section 5.1.1 (p. 5-1) in NEDO-33824 (see (Reference 52) for non-proprietary version) lists the materials used in the manufacture of the steam dryer assembly: [[

]] These materials are less susceptible to IGSCC. The licensee has also implemented several measures during fabrication of the RSD to make it less susceptible to IGSCC and high-cycle fatigue cracking. In the RSD design, the licensee has avoided crevices to the maximum extent possible.

Based on the design analysis submitted, along with successful operating experience with curved vane bank dryer designs, the NRC staff found the BFN RSD design acceptable. The design of the BFN RSDs uses very few structural fillet welds, which makes the RSD less susceptible to fatigue cracking. The use of Type 304L stainless steel, which is resistant to IGSCC, is acceptable to the NRC staff. High cycle fatigue concerns are adequately addressed by inspecting critical locations and accessible welds. However, the staff identified some additional IGSCC-related concerns associated with materials and fabrication of the RSD on any crevices that may be present in the dryer design, solution heat treatment of the material and cold work introduced during fabrication. The licensee stated that every effort has been made to eliminate crevices from the design but some crevices are likely to be present, however, there should not be any IGSCC concern because the carbon content in Type 304L steel is low. In addition, field experience shows an absence of IGSCC at crevices in steam dryers. The licensee has also implemented hydrogen water addition and noble metal chemicals addition to further mitigate IGSCC (Reference 47). The licensee also stated that any cold work introduced during fabrication is limited to 2.5 percent permanent plastic strain. If the cold work exceeds 2.5 percent strain then the affected component is solution annealed. The staff finds that the licensee has implemented adequate measures to mitigate IGSCC in the RSD. The licensee described crack growth analysis results under EPU conditions and confirmed that the weld pass thickness employed during RSD welding is smaller than the critical flaw size. Therefore, a flaw bigger than critical flaw in the root pass or final pass, if present, would penetrate the surface and will be detected by the required liquid penetrant testing. The NRC staff finds the licensee's explanation acceptable because the weld pass thickness being smaller than the critical flaw size under EPU stresses would mitigate fatigue crack growth.

The licensee made several design improvements to the BFN RSDs that fall into three categories, namely (a) functional modifications to facilitate effective installation, (b) design improvements based on lessons learned from the BWR/4 RSD, and (c) design improvements to increase fatigue margin. Since these improvements include additional welds in the dryer structure, which could lead to fatigue failure, the licensee stated that all additional welds are full penetration welds, some of which have a backing plate. The licensee further stated that some of these welds connect three components. The licensee increased the fatigue resistance of these welds in two different ways: (1) by adding additional hood support stiffeners that divert some loads away from the welds thus reducing the fatigue loads, and (2) by increasing the thickness of the components such that the natural frequencies of the corresponding weld region move away from the resonance frequency of the safety relief valve (SRV) standpipes. Some of the additional welds have backing plates so the back side of the welds cannot be inspected during fabrication. For these welds and also for the fillet welds, the licensee has rigorous quality

control guidelines that require laboratory testing of sample welds and destructive evaluation to ensure that no flaws are present at the root of the welds. The NRC staff finds that the improvements implemented in the BFN RSD design make the BFN RSDs robust and more fatigue resistant. The NRC staff also finds that adequate precautions and considerations were implemented in the material selection and fabrication of the BFN RSDs to minimize susceptibility to IGSCC, as well as fatigue cracking.

2.2.6.3 BFN RSD Fluctuating Pressure Loading and High Cycle Fatigue Analysis

2.2.6.3.1 Flow Induced Vibration (FIV) and Mechanically Induced Vibration (MIV) Design Load Definition

Overview

The licensee uses the GEH PBLE software to simulate the acoustic alternating loads on the Browns Ferry RSDs. Mechanically induced loads from the reactor recirculation pump (RRP) are accounted for by applying an additional adjustment factor to the Browns Ferry RSD alternating stress calculations based on a bounding analysis of on-dryer strains measured on the BWR/4 prototype dryer.

The PBLE software was developed by GEH, and has been applied previously to the Grand Gulf Nuclear Station (GGNS) Replacement Steam Dryer in support of the GGNS EPU application. The PBLE has also been used to qualify the Economic Simplified Boiling Water Reactor (ESBWR) steam dryer design. Both the GGNS EPU and ESBWR design certification document (DCD) applications have been previously reviewed and approved by the NRC.

There are two versions of PBLE – PBLE01, and PBLE02. [[

]]. [[

]] that is very similar to Browns Ferry.

PBLE02 is used for design qualification of the BFN RSDs, combining inputs measured on BFN MSL strain gauge arrays installed in all three plants with a [[

]].

All on-dryer strain gauge limits will be recomputed using the revised bias and uncertainty (B&U) based on benchmarking the dryer alternating strain evaluations against the on-dryer strain measurements. Also, PBLE01 will be used for final RSD alternating stress qualification after data are acquired at EPU conditions for the lead unit (BFN Unit 3). Since on-dryer measured data will be available, the recommended minimum alternating stress ratio (MASR) for the lead Browns Ferry unit will be 1.0 (instead of the 2.0 recommended for the design qualification calculations).

PBLE02 will be used for the follow-on units (BFN Unit 1 and BFN Unit 2), since the RSDs in those units will not be instrumented. To update the MASRs and allowable limits in the follow-on plants, the PBLE02 [[ ]] used for design qualification will be replaced using BFN-specific data [[ ]], and the alternating dryer strains and stresses will be recomputed. The end-to-end calculation procedure will be re-benchmarked to generate new on-dryer pressure loading limit curves for monitoring the MASRs for the steam dryers of the follow-on Browns Ferry Units.

Strong tonal loads associated with flow-induced resonance of SRV standpipes is expected to occur in the BFN plants. These loads have been observed in other BWR plants, and conservative estimates of their amplitudes and potential frequencies have been made based on measured data and scale model testing. These 'load adders' ensure the BFN RSDs can withstand the worst-case SRV loads.

RSD loads induced by the tonal pulsations at Vane Passing Frequencies (VPF) in the Reactor Recirculation Pumps (RRPs) are also considered. The VPF loads are accounted for conservatively by (a) retaining the VPF signals [[ ]] and (b) applying an additional stress correction factor based on a [[ ]] benchmark dryer.

Acoustic Loads

The licensee describes the PBLE software used to compute dryer alternating loads in GEH report NEDC-33824P. Both PBLE01 and PBLE02 (Appendix B and Appendix C to NEDC-33824P) have been benchmarked using measured on-dryer pressures and strains in the prototype BWR/4 plant. The application of PBLE to compute BFN RSD loads is described in Section 4 of the report. Both PBLE methods are based on a detailed acoustic model of the steam within the RPV, both outside and within the steam dryer. The mass density of steam, speed of sound, and damping within and outside the dryer are based on well-established data and procedures.

PBLE01 has been approved previously for the GGNS EPU application and the ESBWR DCD; however, PBLE01 was only used for final RSD qualification. PBLE02 was also benchmarked against GGNS data. Many of the elements of the PBLE methods are the same, and use the following:

[[ ]], with assumed boundary conditions at the steam-water interface. The mesh satisfies the standard requirement of at least six elements/acoustic wavelength at the highest analysis frequency. Differences between internal and external steam are properly accounted for.

[[ ]]

[[

]]

These common PBLE elements have not been changed since previous approvals of the GGNS EPU and ESBWR DCD applications, and are therefore appropriate and acceptable for use in the BFN EPU dryer qualification.

There are three PBLE02 elements that required additional staff evaluation for application to the BFN RSDs:

- [[
-
-

]]

Appendix C of NEDC-33824P describes the PBLE02 methodology, along with its benchmarking against measurements made on the BWR/4 prototype steam dryer.

To qualify the three BFN RSDs, the licensee uses a [[

]] The overall procedure [[

]] that is nearly identical to those proposed for the BFN plants.

MSL-Based Acoustic Pressure Measurements

The licensee stated that the PBLE02 method requires estimates of the frequency-dependent left and right travelling wave amplitudes in each MSL, which are used to compute the acoustic particle velocities at the MSL nozzle inlets on the RPV. [[

]] Hoop strain measurements may therefore be used to infer the internal acoustic pressures.

[[

]] Each BFN unit therefore has slightly different MSL strain gauge array spacing.

[[

]]

In addition, the licensee stated that consistent with previously accepted EPU applications, electrical frequencies are filtered from the MSL spectra since they are not related to dryer loading. However, [[

]]. The hoop strain spectra are converted to internal pressures using calibration constants based on the MSL wall thicknesses and elastic moduli. [[

]]

The NRC staff agreed that [[

]]. The general MSL strain/pressure measurement is therefore acceptable.

However, the NRC staff noted that the BFN MSL lower location strain gauge arrays are mounted at different locations in each plant. The licensee provided explanations for the location differences in Enclosure 1 of TVA letter CNL-16-117 dated July 29, 2016 (Reference 28). The lower MSL strain gauge locations differ for several reasons, including [[

]] The licensee confirmed that the different locations do not lead to [[

]] The Browns Ferry lower MSL strain gauge locations are therefore acceptable.

In Enclosure 1 of TVA letter dated July 29, 2016 (Reference 28), the licensee described comparisons of the BFN and prototype BWR/4 RSD loading [[

]] Since the BFN and BWR/4 prototype MSL measurements and resulting loads are consistent [[ ]], the NRC staff finds the MSL-based acoustic pressure measurement procedure reasonable and is therefore acceptable.

Coupled PBLE and PBLE02 TransMatrix

The licensee stated that [[

]].

To further improve the [[

]]

Although the licensee had previously provided plots of the [[ ]] in Appendix C of NEDC-33824P, the NRC staff requested that those terms be compared to those for a [[ ]] in a follow-up RAI. The licensee provided the comparisons in Enclosure 1 of TVA letter dated August 3, 2016 (Reference 31). [[

]]

PBLE02 Benchmarking

The licensee stated that [[

]].

Although not used in the BFN dryer loading development, the benchmarking shows [[

]]

[[

]]. Measured and simulated [[ ]] dryer strains at EPU conditions were used to establish end-to-end bias and uncertainties which are applied to any dryer stress analysis based [[ ]] as described in Section 4.2.5 of NEDC-33824P. [[

]] dryer captures both (a) simulations of RSD loading and alternating strains at CLTP conditions, as well as (b) the procedure [[

]]

The end-to-end benchmarking approach is consistent with that used in previous applications for GGNS EPU and ESBWR design certification, [[

]] Several adjustment factors are also applied to the computed alternating strains (see "Bias and Uncertainty

Adjustment to Stresses" under Section 2.2.6.3 for details). To confirm that the end-to-end alternating strain simulations are indeed bounding and conservative, the licensee provided an analyses in Enclosure 1 of the TVA letter dated July 29, 2016 (Reference 28) that adjusted simulated strains at EPU conditions in [[ ]] bound measurements [[

]] The approach is therefore conservative, and also acceptable for the BFN units. Note that the same bias and uncertainty adjustments made to the simulated alternating strains in the benchmarking are made to the calculated alternating stresses for the BFN RSDs. More details on the adjustment factors are provided in Section 2.2.6.3 under "Bias and Uncertainty Adjustment to Stresses."

Final design loads and comparison to BWR/4 Prototype and Industry Data

The licensee stated that since all three BFN units are nearly identical, as are the RSDs, [[

]]

Rather than compare [[

]]

[[

]]

The Browns Ferry dimensions and operating conditions are nearly identical to those of the prototype BWR/4 plant (detailed comparisons are provided in Section 4.1.7 of NEDC-33824P (see (Reference 52) for non-proprietary version). The acoustic loads on the dryers are therefore expected to be similar. [[

]] The summed loading frequency spectra are similar, but not identical for the Browns Ferry and BWR/4 dryers, with differences attributed to small dryer geometry variations as well as [[

]] It should also be noted that BFN-specific benchmarking for the lead unit at CLTP will supersede the BWR/4 based bias and uncertainties.

The licensee stated that since the Browns Ferry dryer structural response and [[

]] The segments are chosen from the full [[ ]] time record, and have generally the highest observed loads over that full record. [[

]] However, since it is impossible for a short time segment to bound all frequency content, a 'time interval bias' corrects for any underestimates across the full frequency range. The bias is calculated using an approximate scaling approach [[ ]] approved in previous GGNS and ESBWR applications. The scaling approach compares the narrow frequency band content of all [[ ]] time segments spanning the full [[ ]] time record and computes an averaged bias and uncertainty, which are applied to the final alternating stress ratios. The [[ ]] are described in Appendix A, Section 6.3.3 of NEDC-33824P, and were also used and reviewed in the GGNS EPU review.

The dryer stress analysis is conducted using the bounding loads at CLTP conditions. Adjustment factors to increase the stresses to reflect EPU conditions are based on [[

]] Frequency-dependent adjustment factors are computed for [[ ]] Separate adjustment factors are computed for SRV resonance frequencies, as described in the "SRV Acoustic Load Definition," Section 2.2.6.3 of this SE.

NRC staff evaluation

Based on its review, the NRC staff finds that the bias correction factors accounting for the differences between the BFN Unit 1, BFN Unit 2, and BFN Unit 3 dryer loading are appropriately calculated and reasonable. Also, the time interval bias and uncertainty correction factors are computed using methods approved previously for the GGNS EPU and ESBWR design certification applications, and are therefore acceptable for use on the BFN RSDs.

The final BFN RSD design loads, however, appear to be [[

]]. The licensee responded with a revised response in Enclosure 1 of TVA Letter CNL-16-145, (Reference 35), and explained that the [[

]] Since the BFN dryer MASR has been corrected to reflect final loads which are consistent with those of the BWR/4 prototype, the NRC staff finds that the loads are reasonable and acceptable.

SRV Acoustic Load Definition

Browns Ferry has the typical four MSL configuration where the steam line nozzles are offset plus or minus 18° from the 90° and 270° directions. Browns Ferry uses a common SRV

acoustic standpipe configuration for all of the SRV branches. There are three SRV layouts in the MSL configuration, with MSLs A and B being mirror images of MSLs D and C; however, MSL C has one less SRV than MSL B. MSLs A and D have three SRVs. MSL B has four SRVs and MSL C has three SRVs, on opposite sides of the MSL piping from the vessel. There is a reactor core isolation cooling (RCIC) line below the SRV on MSL C and a High Pressure Coolant Injection (HPCI) steam supply line below a dead-leg SRV on MSL B. There is a Reactor Vent line on MSL C, 44 inches below the centerline of the nozzle. Previous testing and analysis have indicated that HPCI, RCIC, and vent lines are not significant contributors to acoustic signal content.

MSLs B and C each have a dead-leg section to accommodate SRVs. Because there is no steam flow in the stagnant dead-leg branches, there is no flow mechanism for exciting the standpipes in the dead-leg section. Therefore, it is not necessary to address potential acoustic resonance frequencies associated with the standpipes in the dead-leg branches.

MSL acoustic data taken at BFN Unit 2 in 2006 (and at BFN Unit 1 in 2007) indicated the [[

]].

Subsequent to the modifications to [[

]] The MSL acoustic data for each BFN unit used in the stress analyses for the RSDs were taken with the AVSs installed. Therefore, it is not necessary to address the potential for acoustic resonance in the standpipes with AVS inserts.

A key part of all steam dryer alternating stress evaluations is assessing the effects of acoustic loads induced by possible flow-excited acoustic resonances in the standpipes of SRVs. Each unit of the BFN has 9 SRVs with their standpipes exposed to steam flow at their open ends. The acoustic modes of these standpipes can be strongly excited when their frequencies coincide with the flow oscillations caused by the instability of the shear layer at the standpipe opening.

There are specific flow rates that drive these acoustic modes, which are usually quite high, such as those at Quad Cities Nuclear Power Station. The BFN MSL flow velocities are [[ ]] at CLTP, and the estimated EPU steam velocity is [[ ]]. In comparison to other BWRs that have received NRC-approved EPU license amendments, the BFN MSL flow velocity at EPU conditions is generally lower than the other BWRs, except the Susquehanna Steam Electric Station, and Peach Bottom Atomic Power Station. Based on staff's review of previous EPUs, the flow velocities for other BWRs at EPU conditions are as follows:

- Susquehanna Steam Electric Station: 153 ft/s
- Peach Bottom Atomic Power Station: 155 ft/s
- Grand Gulf Nuclear Station: 161 ft/s
- Hope Creek Generating Station: 167 ft/s
- Vermont Yankee Nuclear Power Station: 168 ft/s
- Nine Mile Point Nuclear Station, Unit 2: 177 ft/s
- Monticello Nuclear Generating Plant: 179 ft/s
- Quad Cities Nuclear Power Station, Unit 2: 202 ft/s

In Section 4.1.4 of NEDC-33824P, the licensee provided an assessment of the potential for acoustic resonance occurrence in the standpipes as well as an estimate of the dryer acoustic load (design load) which is expected during power ascension to full EPU operation. The procedure of developing the acoustic design load at EPU conditions for the dryers of BFN is similar to that used in the EPU license application of the Grand Gulf Nuclear Station (GGNS). The main difference is that the [[

]] The procedure of developing and projecting the SRV resonance load to EPU conditions for the BFN dryers consists of the following steps:

(a) Evaluating the potential of SRV acoustic resonance to occur during power ascension from CLTP to EPU conditions,

(b) [[

]]

(c) Developing the SRV "load adders" and implementing them into the MSL signals, which are measured at CLTP conditions,

(d) Projecting the simulated SRV pressure loading on the dryer to EPU conditions, and

(e) Developing "scaling factors" for the SRV loading on the dryer and implementing them into the bias and uncertainties of the dryer acoustic loading.

In the following sections, each step is briefly addressed, but additional details can be found in GEH report NEDC-33824P.

(a) Potential of SRV resonance:

The licensee performed [[

]] to estimate the acoustic resonance frequencies. The interaction between various standpipes and the MSLs creates several acoustic modes with their frequencies [[ ]] In order to assess the potential of SRV acoustic resonance occurring when the steam velocity in the MSLs is increased from CLTP to EPU conditions [[ ]], the licensee performed a Strouhal number analysis that considers the acoustic resonance frequencies, the steam velocity in MSLs and the standpipe inner diameters. This analysis indicated that [[

]] Examination of the MSL measurements, the results of the Strouhal number analysis and the simulated acoustic mode shapes showed that [[ ]] on the steam dryer. The uncertainty included in determining the SRV resonance frequency is accounted for [[ ]] In addition to the [[ ]], its amplitude is fixed at the maximum measured value at [[ ]] for all plant conditions between CLTP and EPU. However, the [[ ]] The methodology used to project the SRV resonance amplitude to EPU conditions is discussed below.

(b) [[ ]]:

Because the SRV resonances are not excited up to CLTP conditions, their signature is not present in [[ ]]. The next step was to determine the amplitudes of the acoustic waves in the MSLs. [[ ]].

(c) SRV "load adders":

The SRV load adders]]. The following procedure is used to determine the SRV load adders.

[[

]] Once the SRV load adders are scaled and projected to EPU conditions, which is addressed in the next section, [[

]].

(d) Projecting the simulated SRV loading to EPU conditions:

As mentioned earlier, [[

]] However, for developing the SRV resonance loading, the BWR/4 plant is not prototypical because the SRV standpipe dimensions [[

]]

The SRV resonances postulated for Browns Ferry are first shear layer mode resonances, which typically result in much higher amplitudes than the second shear layer mode resonance measured in the BWR/4 prototype plant.

[[

]] In addition, the [[ ]] plant experienced a very strong SRV resonance at about [[ ]], which caused the failure of the original BWR/3 steam dryers at EPU conditions. The licensee therefore used the [[

]] for developing the design SRV resonance load amplitude for the Browns Ferry acoustic load definition. [[

]].

In developing the Browns Ferry (or the target) SRV resonance load from the resonance growth rate measured in the reference plant, [[

]] These corrections adjust for the geometry differences between the reference plant and target plant that affect the source strength and transmission path between the standpipe and the vessel.

[[

]].

(e) Scale Factors of the SRV design load:

Once the target SRV resonance load at EPU is determined for the BFN dryer, it is used to compute the SRV scale factors that are applied in the final stress adjustment for the load case being analyzed. The SRV scale factors [[ ]] the stresses at the SRV adder frequency to the desired load case value. The steam dryer SRV Scale Factors are simply the [[ ]] The SRV scale factors in this methodology are therefore conceptually similar to the bump-up factors (BUFs) used in previous EPU applications. [[ ]], whereas the BUFs are determined from scale model testing and are applied to the CLTP MSL strain gauge signals to compute the steam dryer pressure load at EPU conditions.

Finally, the SRV EPU scaling factors [[ ]].

The NRC staff noted that the methodology used for the BFN RSDs to compute the design load at SRV resonance and project it to EPU conditions is similar to that used in the license submittal for GGNS EPU operation, which has been thoroughly reviewed by the staff and approved. In both cases, measurements [[ ]] are used to develop the SRV resonance load. In the Browns Ferry case, the [[ ]] experienced a very strong SRV acoustic resonance, excited by the first shear layer oscillation mode, and the available measurements in the RP provide sufficient data to compute and benchmark the dryer load from the dryer pressure data [[ ]].

The NRC staff's review of the MSL geometries in the BFN units and the RP indicated several important differences between the plants, including the number of SRVs on each MSL, their

locations along the MSLs and the acoustic resonance frequencies. In particular, there are three SRVs on each of MSLs A and D in BFN but only two SRVs exist on each of the four lines in the RP. The possibility that acoustic interaction between three neighboring SRVs on two MSLs in BFN may produce stronger resonance than in the case of the RP which involves only two SRVs on each MSL has not been addressed by the licensee. In addition, the dead legs in BFN piping are not present in the RP. Other differences between the BFN and the RP include the SRV resonance frequencies and the ratio between the diameters of the standpipe and the MSL. These differences affect the Strouhal number (or the dimensionless steam velocity) at resonance, the lock-in range (i.e., the steam velocity range during which the SRV resonance is excited) and most importantly, the resonance amplitude during the lock-in range.

Since the SRV acoustic resonance mechanism is a non-linear phenomenon, the above mentioned differences may affect the response intensity of MSLs to SRV resonances and thereby distort the scaling factors of the SRV adders. Additional information was needed to confirm that, despite the differences between the BFN plants and RP, the data of the RP are appropriately used to predict the acoustic design load on the BFN dryers.

The licensee provided the results of scale model tests (SMTs) for BFN Units 1 and 2 in Enclosure 4, "CDI [Continuum Dynamics, Inc.] White Paper No. 16-11, dated July 2016," of TVA letter dated August 3, 2016 (Reference 31). These tests were performed on an one-eighth scale model of the BFN reactor dome and 4 MSLs including all SRVs and blind flanges. The complete test procedure and results can be found in CDI Report No. 08-14-P (Reference 144). The staff reviewed the white paper and the full SMT report and established that the SMT of BFN conforms to those submitted and approved in earlier EPU license applications. In general, the main objective of these SMTs is to determine the bump-up-factors (BUFs) which relate the SRV resonance load at EPU to that measured in-plant at CLTP conditions. Based on the SMT results, the BUFs for Units 1 and 2 of BFN are found to range from 1.7 to 3.5. The use of SMT-based BUFs to estimate the SRV dryer loading at EPU conditions has been approved by NRC staff for several EPU applications.

In order to show the conservatism of the SRV design load for BFN steam dryers, the licensee used the scaling factors of load adders to compute the steam dryer pressure ratio between projected EPU design load and CLTP load at the SRV resonance frequency [[ ]]. The CLTP load is calculated by means of PBLE02 methodology from the CLTP measured MSL pressures. The EPU design load is computed by applying the scaling factors developed from [[ ]].

The licensee reported that the pressure ratio of EPU design load to CLTP load at the SRV frequency band [[ ]] Since the minimum design load ratio [[ ]] is substantially greater than the largest SMT-based BUF (3.5), the SRV design load used in the stress analysis of BFN dryer is more conservative than the load that would result from using the SMT based BUFs. The licensee therefore concluded that this comparison proves the conservatism of the SRV design load which is used in the stress analysis of the BFN steam dryers at EPU conditions.

The staff reviewed the licensee's response, CDI white paper, and the initially submitted SMT report and found the SMT-based BUFs to be appropriately determined. The use of these BUFs to compute the SRV loading at EPU, as implemented in previous EPU applications, would result in a lower load than the design load used by the licensee in the stress analysis of the dryer. The staff also agrees that the [[

]], which will be applied to the design load of the dryer.

With respect to the [[

]] Although this procedure provided a reasonable spreading of the SRV load over the dryer surface, it does not appear to guarantee that the maximum dryer stress produced by other pressure distributions will always be smaller than that produced by the optimized pressure load. The licensee repeated the [[ ]] study of the SRV load adders, but using dryer stress as a metric instead of [[ ]].

In Enclosure 1 of TVA letter dated September 23, 2016 (Reference 35), the licensee described that a [[

]] The MASR for the upper and lower dryer portions obtained from the [[ ]] DOE with dryer alternating stress as a metric are then compared with those of the baseline case obtained from the [[ ]] DOE with normalized pressure on the dryer taken as a metric. Using the dryer alternating stress as a metric in the DOE produced negligibly small effects on the MASR; it remained at [[ ]] for the lower dryer and decreased slightly from [[ ]] for the upper dryer section. Therefore, the licensee concluded that the [[ ]] optimization presented in the NEDC-33824P (based on the dryer pressure load) is providing practically the same MASR as an optimization based on the dryer stress as a metric. The NRC staff finds this response acceptable because the MASR remained practically the same when the metric of phase optimization is changed from normalized pressure to alternating stress of the dryer. The resulting MASR over the whole dryer decreases by only 0.5 percent.

In trending and projecting of the pressure load on BFN dryers at the SRV resonance frequency, the licensee used [[

]] to develop the SRV load distribution on the dryer surface and the bias used compensates for the difference between the projected versus measured response. Therefore, this bias provides the adjusted [[ ]] pressure load at the resonant frequency. On the other hand, the bias adjustment for the BFN acoustic design load definition is included in the end-to-end B&Us obtained from benchmarking PBLE02 as described in Section 4.2.5.1 of NEDC-33824P. The NRC staff finds this reasonable because PBLE02 uses end-to-end B&Us derived from comparing the measured dryer stresses with those projected from MSL measurements. These B&Us are appropriately implemented in the dryer stress analysis procedure. The staff also agrees that the differences between the plants are compensated for in the scaling factors of the pressure load definition which are addressed in Section 4.1.4.4.2 of NEDC-33824P. These scaling factors are shown to be considerably conservative in the licensee's letter dated August 3, 2016 (Reference 31).

In summary, although there are some important differences between the designs of the MSLs in Browns Ferry and the reference plant, the licensee has accounted for these differences by means of [[ ]], which have been shown to include a considerable amount of conservatism. The staff finds the SRV design load definition for BFN steam dryers to be reasonable, including having sufficient conservatism, and therefore is acceptable.

Reactor Operating Condition Effects and RRP VPF Loads

The licensee stated that reactor operating conditions vary slightly during a fuel cycle, and can affect dryer loading as discussed in Section 4.1.5 of NEDC-33824P. To compensate for fuel rod degradation, reactor recirculation pump and core flow rates increase. [[ ]] The MSL steam flow speeds and steam dome pressures can also change slightly throughout a fuel cycle. These changes, though minor, can alter dryer loads and therefore alternating stresses. The Browns Ferry RPV dome pressures are held to within plus or minus 1 percent of the nominal levels, so that the effects on dryer stresses are [[ ]]. The water level changes are more significant, but the licensee argues that [[ ]].

The largest operating condition change during a fuel cycle is typically in the RRP drive frequency, which in turn shifts the Vane Passing Frequency (VPF) of the RRP impeller. BFN VPF frequencies at variable plant conditions are tabulated in Tables 3-1, 3-2, and 3-3 in Appendix D and table 4.1-2 of NEDC-33824P, and are between [[ ]] at CLTP in the three BFN plants. These frequencies will increase at EPU conditions.

The tonal vibrations and pressures caused at the RRP VPF frequency can be significant, and must be accounted for in the RSD stress analysis. [[ ]] The bounding analysis using the BWR/4 dryer strain data (described in Section 4.1.5.4 of NEDC-33824P) led to a BFN VPF stress adjustment factor of [[ ]] for the lower dryer and [[ ]] for the upper dryer. These factors include all possible transmission paths for the VPF tones. Therefore, [[ ]] adds extra conservatism to the VPF assessments, which is acceptable.

The VPF and SRV resonance frequencies are similar in the BFN plants. Since the VPF will shift depending on variable pump speeds throughout a fuel cycle, it is possible that the VPF and SRV frequencies may coincide. There is no in-plant information on this possible coincidence and its potential effects on dryer loading.

[[ ]]. The NRC staff's review of the licensee's approach finds it conservative and acceptable.

However, there may be possible loading amplification effects due to coincidence between VPF and SRV resonance frequencies. The licensee explained in Enclosure 1 of TVA letter dated June 6, 2016 (Reference 21), that the [[
]]. This assertion is not substantiated quantitatively and the VPF and SRV tones should therefore be monitored during power ascension. The strengths of SRV resonances are highly sensitive to acoustic oscillation amplitude, which may be affected by MSLs which vibrate in response to VPF structural excitation. The staff also asked the licensee to assess the effects of coincident SRV and VPF frequencies during power ascension. The licensee responded in Enclosure 1 of TVA letter dated July 29, 2016 (Reference 28). The power ascension test plan (PATP, NEDC-33824P, Appendix E, Section 3.2) for the lead unit instrumented dryer includes a test series where the power is held approximately constant and the core flow varied over the licensed core flow operating range. Any significant amplification observed during the power ascension to EPU along with maximum load line limit analysis (MELLLA) rod line or during the core flow sweep test will be reported to the NRC following completion of the testing, thereby assessing the impacts of coincident VPF and SRV resonance across the range of potential SRV resonance frequencies. The above commitment is included in license condition (14)(b) 4.b. The licensee's approach will address the NRC staff's concerns, and therefore is acceptable.

Steam Dryer High Cycle Fatigue Stress Analysis

Steam dryer finite element model

The licensee stated that the structural evaluation of the Browns Ferry RSDs for high-cycle acoustic loads is presented in NEDC-33824-P (Attachment 40 to the EPU LAR (Reference 1)). The fluctuating acoustic pressure loading, described above in SE Section 2.2.6.4.1, was applied to a structural finite element model of the RSDs. Finite element analysis (FEA) was performed using the ANSYS General Purpose Finite Element Code. [[
]] of critical damping as recommended by RG 1.20 (Reference 142).

The ANSYS software was used to perform the stress analysis of the Browns Ferry RSDs subject to acoustic loads at CLTP operating conditions. The Browns Ferry RSD finite-element models (FEMs) are described in NEDC-33824-P. BFN Unit 3 will have an instrumentation mast and the associated brackets on the dryer top girders for attaching the instrumentation cables. The mast will be subsequently removed. BFN Units 1 and 2 do not have an instrumentation mast. The BFN Unit 3 instrumentation mast will be in place during power ascension to EPU and subsequent completion of the end-to-end benchmarking. Then at the first subsequent refueling outage, the instrumentation mast will be removed. For the BFN Unit 3 RSD, FEMs with and without an instrumentation mast were utilized.

The FEMs for the RSD mostly consist of shell elements and some solid elements with shell-to-solid transitions using [[

]]. The trough spargers and the tierods located inside the valve modules are represented by beam elements. The vane bank modules are box-like structures with many internals such as chevrons hanging on tie rods. [[

]] Since the dryer skirt is partially submerged in water, the finite element modeling of the skirt is separated into components [[

]], which corresponds to the bottom of the support ring where the dryer sits on the vessel lugs.

The NRC staff reviewed the Browns Ferry RSD structural finite element modeling, the boundary conditions, and stress analysis for acoustic loads. The approach and methodologies utilized for Browns Ferry are reasonable and consistent with dryer analyses in the previous NRC-approved EPU applications, especially the GGNS application. However, the staff had a concern about the specific shell elements used in the finite element model for the RSD. Specifically, the NRC staff questioned how the use of specific shell elements affects the estimation of peak stresses. In response, the licensee stated that ANSYS recommends the use of ANSYS Shell 181. The main difference between the three different shell elements is how the transverse shear is treated by these elements. Shell 181 assumes parabolic distribution of shear stress through the thickness, Shell 43 assumes uniform shear, and Shell 63 assumes that transverse shear is negligible. Shell 43 and Shell 181 may be used to model thin to moderately thick plates. The licensee analyzed a test problem with a structure of material and thickness similar to that of the Browns Ferry RSDs and demonstrated that these two elements give the same results for the peak stress whereas Shell 63 gives higher peak stresses. Therefore, the staff finds that the use of Shell 43 and Shell 63 for modeling Browns Ferry RSDs is acceptable.

The finite element model of the steam dryer is supplemented by water elements surrounding the immersed part of the dryer skirt. The modeled water volume surrounding the skirt bottom consists of an outer annulus (between the skirt and wall of the RPV) and an inner annulus (between the skirt and the water separator tubes). The boundary condition [[

]].

The NRC staff had some concerns about the boundary conditions imposed on the [[

]]. The licensee was requested to explain why these boundary conditions were chosen as they seem to increase the water resistance to skirt movement and therefore may artificially decrease the simulated skirt vibration amplitude. In response, the license explained that the [[

]]. The licensee also added that similar boundary conditions were used in the benchmarking process of the BWR/4 steam dryer.

The NRC staff finds the licensee's response acceptable because [[ ]] and also because the boundary constraints on the water modeling in the BFN analysis are similar to those implemented in the BWR/4 prototype dryer benchmark analysis. Any analytical uncertainty will be included in the [[ ]], which uses the same type of skirt water modeling.

The structural evaluation performed by the licensee follows the guidance from BWRVIP-182-A (Reference 143), RG 1.20, 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.

Substructure

A typical BWR steam dryer has about 20 vane bundles. The licensee modeled each vane bundle with [[ ]] so that the geometry and construction of each vane bundle can be represented with sufficient detail. Since it is impractical to include such a detailed model for a vane bundle in the global finite element model, the licensee represented this detailed model by [[ ]] with a limited number of predefined master degrees-of-freedom (DOFs). [[ ]].

The licensee selected the master DOFs at certain nodes on the boundary of the detailed model of the vane bundle; these nodes correspond to nodes on the other dryer components in the [[ ]].

The licensee showed the adequacy of [[ ]] for the vane bundles is acceptable.

Mesh convergence studies

The licensee has performed submodel analyses of high stress locations (alternating stress ration less than 6.0) in the Browns Ferry RSD to determine the mesh convergence error. [[

]].

The mesh convergence studies performed for the Browns Ferry dryers are similar to those performed for the ESBWR dryer design and are improved over the studies performed for the Grand Gulf RSD. In the Grand Gulf RSD, the mesh convergence study was [[ ]], whereas in Browns Ferry the mesh convergence studies results are extrapolated to zero mesh size and the resulting stresses are used to determine the convergence factor. Thus, the mesh convergence studies performed for the Browns Ferry RSDs are conservative. In addition, the licensee applied a convergence factor of 1.1 to the global stress analyses results for all the FEM components; which bounds the estimated convergence factors for all the high stress locations. Therefore, the NRC staff finds the Browns Ferry convergence study results are reasonable and therefore acceptable.

Vibration Analysis Approach

The licensee used a [[ ]] analysis of the steam dryer subject to the fluctuating pressure loads determined by the PBLE methodology. Since the PBLE loads are estimated in the [[ ]] and then mapped on to the inside and outside surfaces of the dryer panels. The resulting differential pressure loads are applied to the steam dryer structural finite element model.

Field experience has shown that the frequency range of the fluctuating hydrodynamic loads which cause high-cycle fatigue cracking of the steam dryer [[ ]]. In addition, the alternating maximum peak stress intensity may occur infrequently, sometimes less than once per second. Therefore, the licensee performed a [[

]]. This is done so that the [[ ]]. The licensee uses a [[

]]. The time segments are chosen to maximize dryer loading. As discussed under "Bias and Uncertainty Adjustment to Stresses," in Section 2.2.6.3, time interval bias and uncertainty corrections are applied to the [[

]].

The licensee specified [[ ]] vibration damping during the stress analysis, as recommended by RG 1.20. [[

]].

Displacement boundary conditions were applied to the dryer at the support brackets, which are welded to the reactor pressure vessel wall. The dryer support ring rests on the brackets which constrains its [[

]].

The licensee performed the [[ ]] analysis at the current power level (i.e., CLTP). In addition, [[

]] analyses were completed, the FEA results were screened for the maximum stress intensity for each steam dryer component. These stresses were further processed by applying appropriate fatigue strength reduction factors (FSRFs) and plate thickness factors (PTFs). The licensee used FSRFs of [[

]], as well as other stress amplification factors, are discussed in Section 2.2.6.3 under "Bias and Uncertainty Adjustment to Stresses."

The [[ ]] analysis performed by the licensee using ANSYS is a well-accepted method for dynamic analysis. Use of a [[ ]] frequency range for fluctuating hydrodynamic loads is based on the [[ ]] for EPU operation. Displacement boundary conditions assume [[

]] to account for the approximations in modeling the dryer mass and stiffness. Second, the stress analysis of the [[

]]. The NRC staff finds this explanation acceptable.

The NRC staff had a concern about the [[

]] for the following reasons: (1) the hydrodynamic loads acting on the BWR/4 prototype dryer and the Browns Ferry dryer have similar frequency content including the critical excitation frequencies, (2) the finite element models [[

]].

Browns Ferry Replacement Steam Dryer Functional RPV Interface Attachments

The RSD support ring is supported by the reactor pressure vessel at four locations. At two locations 180-degrees apart it is supported by seismic blocks, which are welded to the support plate. [[

]]. They carry the dead weight of the dryer and resist its [[

]]. In addition, the jack bolt/latch mechanism prevents the lifting of the RSD during operation. The seismic blocks are made of Type 316L stainless steel. This material has a design stress intensity (Sm) of [[ ]], and an alternating stress intensity limit (Sa) of 13,600 psi. The jack bolt/latch mechanisms are made of X-750 nickel alloy. This material has a Sm of [[ ]], and the Sa is [[ ]].

The reaction forces acting on the supports are extracted from the RSD stress analysis. The stress analysis results for these supports are discussed in Section 2.2.6.4. For fatigue assessment of the seismic blocks, [[

]]. The resulting ASRs for the jack bolt/latch mechanism are greater than 2.0.

The licensee altered the design of the dryer to obviate the need for a weld between the seismic block and the skirt that caused fatigue cracking at EPU in a replacement steam dryer at another BWR plant. In the jack bolt/latch mechanism, the licensee similarly altered the design to reduce potentially troublesome welds, and properly accounted for the stress concentration factors at thread roots and latch mechanism. The fatigue analysis of these two supports show that the MASR is greater than 2.0. Therefore, the NRC staff finds the support designs acceptable.

Bias and Uncertainty Adjustment to Stresses

The licensee has applied several factors to the raw alternating stresses calculated using the procedures described in Section 2.2.6.3 to obtain the final stresses within the dryer. Bias factor corrections are:

- [[
-
-
-
-
-
-
-
-

]].

[[

]]. The dryer structural mesh convergence bias factor is discussed under "Mesh convergence studies" in Section 2.2.6.3. The frequency-dependent bias factor to account for [[

]].

[[

]] (described under "SRV Acoustic Load Definition" in Section 2.2.6.3 of this SE). [[

]].

The different bias and scale factors applied to the raw BFN RSD alternating stresses are reviewed in other sections of this safety evaluation report and found to be acceptable. [[ ]] is evaluated in Section 2.2.6.3 under *"PBLE02 Benchmarking."* [[ ]] are evaluated in Section 2.2.6.4.1.4, *Reactor Operating Condition Effects and RRP VPF loads.* The bias factors to account [[ ]] are evaluated in Section 2.2.6.3 under "Final design loads and comparison to BWR/4 Prototype and Industry Data." The EPU scale factor is evaluated in Section 2.2.6.3 under "SRV Acoustic Load Definition." Thus each factor discussed here has been evaluated and found to be acceptable. Therefore, the NRC staff finds the process used by the licensee to convert the raw stresses to the adjusted stresses acceptable.

Acceptance Criteria and Minimum Alternating Stress Ratio

The BWR steam dryer is not a safety component and, therefore, its design is not governed by the ASME Code. However, the licensee has designed the RSD following the ASME Code Subsection NG 3000 with two exceptions: (1) [[ ]], and (2) no temperature adjustment for the modulus of elasticity is performed when comparing the calculated alternating stress intensity against the fatigue acceptance criterion.

The licensee used the design fatigue curves for Austenitic Ni-Cr stainless steel as given in the ASME BPVC Section III, Division 1, Appendix I (Reference 145). The licensee used fatigue Curve C, which accounts for the maximum allowable mean stress. This curve has an allowable alternating stress amplitude of 13,600 psi at 10^{11} cycles. The licensee compared the maximum stress intensity and the maximum stress at the weld in each component with the curve C and determined the ASR, which is equal to 13,600 psi divided by maximum computed stress intensity. The licensee showed that the minimum alternating stress ratio (MASR), which occurs at the [[ ]]. Thus the RSD design satisfies the NRC recommendation for all practical purposes.

The NRC staff has reviewed the licensee's discussion on the acceptance criteria and minimum alternating stress ratio and finds it mostly acceptable because a similar approach was taken for the GGNS RSD during its EPU application. The one exception is the licensee's position related to high-cycle fatigue assessment of the RSD. The licensee did not perform a temperature adjustment for the modulus of elasticity when comparing the calculated alternating stress intensity against the fatigue acceptance criterion. This is a non-conservative position because such an adjustment would increase the calculated alternating stresses. Such an adjustment was used in previous EPU dryer applications because the fatigue curves present in the current version of the ASME code represent strain-controlled test results. The licensee agreed to perform a temperature adjustment for the modulus of elasticity, which will increase the calculated stresses by 11 percent. But the licensee points out a need for another temperature adjustment related to the effect of the mean stress on the endurance limit. At room temperature, the endurance limit of austenitic stainless steel (i.e., Types 304 and 316) is lower than its yield strength. As a result, according to a Modified Goodman Diagram, the increase in

the mean stress would reduce the endurance limit. At room temperature, the maximum reduction in the endurance limit is about 18 percent. However, at BWR operating temperatures, the endurance limit is equal to or greater than the yield stress and, therefore, the mean stress has no effect on the endurance limit. As a result, the temperature effect will require an 11 percent increase in the calculated stresses and 18 percent increase in the endurance limit. Therefore, it will be conservative to not account for the temperature effect in the high-cycle fatigue assessment of the RSD when using the high cycle fatigue (endurance) limit of 13,600 psi. The NRC staff finds this explanation related to the temperature effect acceptable.

2.2.6.4 Browns Ferry Nuclear Plant RSD Primary Stress Evaluation

The licensee provided material properties, ASME Code stress limits (Reference 146), design load combinations, and the primary stress evaluation for the steam dryer in Section 5.0 of NEDC-33824P (see its non-proprietary version in (Reference 147)). The methodology and load combination details are described in NEDC-33824P, Appendix A, Section 8. In addition to the evaluation for FIV loading and high-cycle fatigue, the licensee evaluated the steam dryer for the normal, upset, emergency, and faulted ASME load combinations to demonstrate its structural integrity. The licensee utilized subsection NG of the ASME Code Section III for guidance. Plant specific load combinations are followed. For normal conditions, the load combinations include dead weight, differential pressure (ΔP), and the FIV. The loads utilized for upset conditions include dead weight, ΔP, acoustic load caused by turbine stop valve (TSV) closure, SRV loads, operating basis earthquake and the FIV. The emergency condition loads include dead weight, ΔP, and the FIV. The faulted condition loads include dead weight, ΔP, safe shutdown earthquake (SSE), acoustic load (from MSLB outside containment, and the FIV. The steam dryer is at uniform temperature at normal and transient conditions, and therefore the thermal expansion stress is considered zero. There is no radial constraint of the dryer, and differential expansion is accommodated by clearances. Therefore, there are only primary stresses and no secondary stresses on the dryer.

The membrane and membrane plus bending stress intensities are computed and compared with the allowable limits. The allowable limits for membrane stress intensities for normal (service level A), upset (service level B), emergency (service level C), and faulted (service level D) conditions are, respectively, 1 Sm, 1 Sm, 1.5 Sm, and lesser of 0.7 Su or 2.4 Sm, where Sm and Su are the allowable stress intensity and tensile strength of the material at the applicable temperature. The allowable limits for membrane plus bending stress intensities for normal (service level A), upset (service level B), emergency (service level C), and faulted (service level D) conditions are 1.5 Sm, 1.5 Sm, 2.25 Sm, and lesser of 1.05 Su (1.5 x 0.7 Su) or 3.6 Sm (1.5 x 2.4 Sm), respectively.

The ratios of the allowable membrane stress intensity to the computed stress intensity for the dryer at the most limiting component are as follows:

Normal: [[ ]]
Upset: [[ ]]
Emergency: [[ ]]
Faulted: [[ ]]

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 at EPU conditions are as follows:

Normal:	[[ ]]
Upset:	[[ ]]
Emergency:	[[ ]]
Faulted:	[[ ]]

The licensee also evaluated the BFN RSD with RPV attachments based on reaction forces at the attachment locations for normal, upset, emergency and faulted load combinations. The components are seismic block latch, latch nut, and jack bolt. The material for seismic block is SA-240 TP 316, and the material for latch, latch nut, and jack bolt is X-750. Maximum primary stress ratios (ASME Code Allowable stress intensity / Maximum primary stress intensity) are summarized below:

Normal:	[[ ]]
Upset:	[[ ]]
Emergency:	[[ ]]
Faulted:	[[ ]]

Maximum primary membrane plus bending stress ratios (ASME Code Allowable stress intensity / Maximum primary membrane plus bending stress intensity) are summarized below:

Normal:	[[ ]]
Upset:	[[ ]]
Emergency:	[[ ]]
Faulted:	]]

Shear stress ratios (ASME Code Allowable Shear stress /computed shear stress) are summarized below:

Normal:	[[ ]]
Upset:	[[ ]]
Emergency:	[[ ]]
Faulted:	[[ ]]

Thread shear stress ratios (ASME Code Allowable thread Shear stress /computed thread shear stress are summarized below:

Normal:	[[ ]]
Upset:	[[ ]]
Emergency:	[[ ]]
Faulted:	[[ ]]

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. The licensee also evaluated steam dryer / RPV interface modeling for acceptability. Based on a review of the above results, the NRC staff finds the estimated 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.

2.2.6.5 Monitoring During Power Ascension and Final Assessment at EPU

RG 1.20 Comprehensive Vibration Assessment Program

In Section 6 of Attachment 40 of the LAR (see (Reference 147)) and for the non-proprietary version (Attachment 41)), the licensee described the RG 1.20 requirements related to the RSDs. For high cycle fatigue analysis of the RSD, the licensee used fatigue limits of 13,600 psi as specified by ASME Section III. In addition, the predicted MASR of [[ ]] at the maximum predicted fatigue stress location satisfies the recommendation of MASR of 2.0 for all practical purposes. The licensee further described how the methodology employed for the fatigue analysis of the RSD meets the recommendations specified in RG 1.20 (Reference 142).

The licensee classified the BWR/4 dryer as a valid prototype and, with respect to this dryer, it classified the BFN lead plant RSD as non-prototype Category II. This classification of the lead plant RSD is justified because its design is somewhat modified from the BWR/4 prototype dryer. Also, pressure loads acting on these two dryers are similar as discussed in Section 2.2.6.3. The design and the pressure loads for the remaining two BFN RSDs are similar to those for the non-prototype Category II, and they are classified as non-prototype Category I.

The design vibration and stress analysis for the three BFN units are the same as discussed in Section 2.2.6.3. An RSD with on-dryer instrumentation is planned to be installed during the spring 2018 refueling outage of BFN Unit 3. 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 a BFN specific end-to-end benchmark. The licensee will perform a confirmatory analysis of the lead plant RSD at the end of its power ascension to EPU. The confirmatory analysis will include a final load definition and reanalysis using the end-to-end bias and uncertainties determined by comparing the measured strains and pressures with the corresponding predicted results under EPU conditions. The lead unit confirmatory analysis will also lead to updated acceptance criteria for the two follow-on units. The confirmatory analysis for each follow-on unit will be performed using the corresponding MSL pressures and the end-to-end B&Us based on the lead unit analyses. The confirmatory analysis for the follow-on unit will address any significant difference observed between the MSL measurements for the follow on unit and those for the lead unit.

As described in Section 2.2.6.8, "License Condition – Potential Adverse Flow Effects," the RSD for the lead plant will be monitored using the on-dryer instrumentation during power ascension. In addition, the MSLs of the lead plant will be instrumented with new strain gauges so that the acceptance criteria for the follow-on units can be developed. The acceptance criteria for the lead unit include peak value limits and limit curves on the on-dryer instruments based on the FIV analysis as discussed in Section 2.2.6.3. The acceptance criteria for the follow-on units are based on the PBLE02 projected steam dryer loads computed from the MSL pressure measurements and an updated BFN-specific TransMatrix. Limits will be based on the dryer loads and the updated MASR from the lead dryer confirmatory analysis.

During the first two scheduled refueling outages after reaching full EPU power conditions, a visual inspection of the critical locations on the RSD will be conducted for each unit. The inspection plan will be consistent with the industry guidance.

The NRC staff has reviewed the comprehensive vibration assessment program for the RSDs for the three BFN units. The staff finds that this program closely follows the recommendations of RG 1.20. The categorization of the lead RSD and two follow-on RSDs is acceptable. The licensee's plan to develop BFN-specific end-to-end B&Us using the measured and predicted data for the instrumented lead RSD at EPU is similar to the one used for GGNS RSD and is found acceptable. These BFN-specific B&Us will also be used for the stress analyses of the two follow-on RSDs. Similar practice was followed for the follow-on Peach Bottom RSD and is found acceptable. The inspection plan during the first two scheduled refueling outages after reaching full EPU power is similar to the one used for other RSDs that have received EPU licenses. Therefore, based on the above, the NRC staff finds the comprehensive vibration monitoring plan for the three BFN RSDs acceptable.

Limit Curves and Limit Curves Adjustment

The license provided Level 1 and Level 2 on-dryer strain based limit curves in Appendix-E.1 of NEDC-33824P for the [[ ]] on-dryer strain gauges to be installed on BFN Unit 3. Also, Table 5.3-1 in Appendix-E of NEDC-33824P provides Level 1 and Level 2 strain limits for the [[ ]] on-dryer strain gauges to be installed on BFN Unit 3. Level 1 and Level 2 MSL based limit curves are provided in Appendix-E.1 and Appendix E.2 of NEDC-33824P.

Limit curves and limit curve adjustment procedures vary for each of the BFN plants. The general procedures are described in NEDC-33824P, Section 6.3 and Appendix A, Sections 9 and 10, as well as in the license conditions. The licensee also clarified its limit curve specifications in Enclosure 1 of the TVA letter dated September 23, 2016 (Reference 35). The initial lead unit limits on on-dryer strains include time domain peak values and PSDs based on the design basis calculations. After BFN-specific MSL and on-dryer strain data are acquired at power levels up to CLTP, the peak limits and PSD limit curves will be reevaluated. If the measured strains exceed the design basis limits or if the design basis calculations have not adequately captured the measured dryer response, the BFN RSD alternating stresses will be reanalyzed using BFN-specific loads. Then, BFN-specific end-to-end bias and uncertainties will be calculated, and new peak and PSD limits will be specified for on-dryer strains. The updated limits will be based on an MASR of 1.0, since they will be based on on-dryer BFN measured data.

However, if the lead unit on-dryer instrumentation data are corrupted significantly prior to reaching CLTP, the original design basis limits will be used throughout power ascension. In this case, power ascension limits and license conditions will ensure that the design basis [[ ]] will not be violated. Along with the on-dryer strain limits, BFN-specific on-dryer loading limit curves will be developed [[ ]]. These loading limit curves will be monitored, if the on-dryer strain gauge data are corrupted during power ascension.

During power ascension of the lead unit to EPU, the on-dryer alternating strains will be monitored and compared to the acceptance limits. At each power level the dryer strains will also be projected to the next power level, as well as to full EPU power. In the event the on-dryer strain data are corrupted, on-dryer loading will be computed [[

]] and compared to allowable limit curves. The on-dryer loading will be projected to the next power level and EPU power. If either the strain-based or loading-based Level 1 acceptance limits are violated, the dryer MASRs will be reevaluated, and the acceptance limits updated.

If the lead unit on-dryer strain measurements and MSL strain gauge measurements are acceptable, the limit curves for the follow-on plants will be based on BFN-specific dryer MASR calculations using PBLE02 and an updated BFN-specific TransMatrix. Limit curves will be established for on-dryer loading [[ ]]. Limit curve updates will be triggered by Level 1 violations, just as they will be for the lead unit. Dryer MASR reanalysis will be used to establish the revised limits.

The NRC staff finds the limit curve adjustment procedures reasonable. The licensee supplemented Sections 6.3 and Appendix A, Sections 9 and 10 and provided further justification to include commitments as license conditions in the discussion of Table 25-2 in Enclosure 1 of its letter dated September 23, 2016 (Reference 35). If the lead unit on-dryer strain and MSL data are of acceptable quality through CLTP conditions, the limit curve adjustment procedures should be acceptable and conservative. If, however, the lead unit on-dryer data are corrupted, the design basis limit curves will be used, and there are no acceptable means of modifying these limits during power ascension. In the latter case, the design basis limits and license conditions will assure that the design basis [[ ]] will not be violated. The use of these limit curves and limit curve modification approaches provides reasonable assurance that the BFN RSD structural integrity will not be compromised, and thus, the NRC staff finds them acceptable.

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 Browns Ferry limit curve approach during EPU power ascension to be acceptable.

2.2.6.6 Steam Feedwater, and Condensate Systems and Components

Increased flow rates and flow velocities during operation at EPU conditions are expected to produce increased FIV levels in some piping systems and components. The licensee, in Attachment 45, "Flow Induced Vibration Analysis and Monitoring Program" (Reference 148) of the LAR, addresses in detail the analyses and testing program undertaken by the licensee based on industry operating experience to provide assurance that unacceptable FIV issues are not experienced at BFN plants due to EPU implementation for the affected piping systems.

Displacement transducers are installed at selected locations on the main steam piping inside containment to monitor vibrations. Accelerometers are installed at selected locations on feedwater piping, and feedwater flow control valves inside containment to monitor vibrations. At these locations, the licensee has measured baseline vibration levels at CLTP and projected vibration levels at EPU, and specified acceptance criteria to monitor during the power ascension.

Displacement transducers are installed at selected locations outside the containment to monitor vibrations: main steam piping, main steam stop and control valves, feedwater piping (located

near the reactor feed pump (RFP) discharge), and RFP vent lines. At these locations, the licensee has measured baseline vibration levels at CLTP and projected vibration levels at EPU, as well as acceptance criteria to monitor during the power ascension.

In addition, accelerometers are installed on selected main steam valves including MSIV, RCIC valve, HPCI valve, and SRVs, to monitor vibrations. At these locations, the licensee has measured baseline vibration levels at CLTP and projected vibration levels at EPU, and specified acceptance criteria to monitor during the power ascension. Further, vibrations will be monitored at selected locations on condensate piping, extraction steam piping, and heater drain piping. The acceptance criteria for vibrations are based on the ASME OM-3 Code (Reference 149)

The NRC staff's review of steam, feedwater, and condensate systems and components is covered under Section 2.2.2.2 of this SE. As stated in that section, the NRC staff concludes that the licensee, using the current design basis and code of record, has adequately addressed the effects of the proposed EPU on the BOP piping, pipe components and pipe supports.

Based on its review, as summarized above, and contingent upon satisfactory completion of the license conditions in Section 2.26.8, the NRC staff concludes that the licensee has an acceptable monitoring plan based on industry operating experience to ensure that the proposed EPU does not adversely affect the structural integrity of the steam, feedwater, condensate, extraction, and heater drain systems and components.

2.2.6.7 Conclusions

The NRC staff has reviewed the licensee's evaluations of potential adverse flow effects on the main steam, feedwater, and condensate systems and their components (including the steam dryer) for the operation of BFN Units 1, 2, and 3 at the EPU power level as discussed in Sections 2.2.6.1 through 2.2.6.7 subject to the license conditions in this SE. The staff concludes that the licensee has provided reasonable assurance that the flow-induced effects on the replacement steam dryer and other plant equipment are within the structural limits at CLTP conditions and extrapolated EPU conditions. The RSDs of the three Browns Ferry units will maintain their structural integrity and will perform satisfactorily under the proposed EPU conditions because there is conservatism in the loadings considered as well as significant margin [[ ]] as indicated by [[ ]]. Subject to the license conditions in Section 2.2.6.8 of this SE, the NRC staff concludes that there is reasonable assurance that the BFN RSDs will maintain their structural integrity at the projected EPU conditions.

The NRC staff further concludes that the licensee has demonstrated that the main steam, feedwater, and condensate systems and their components (including the replacement steam dryers) will continue to meet the requirements of draft GDC-1, 2, 40, and 42 following implementation of the proposed EPU at Browns Ferry. Therefore, the NRC staff concludes that the license amendment to operate the three BFN units at the EPU conditions regarding the steam dryer is acceptable with respect to potential adverse flow effects for high-cycle fatigue as well as to withstand the ASME Code normal, upset, emergency, and faulted load combinations.

2.2.6.8 License Condition - Potential Adverse Flow Effects

2.2.6.8.1 Unit 3 License Condition - Potential Adverse Flow Effects

The following will be added to the BFN Unit 3, Renewed FOL as license condition 2.C.(14) as shown in Supplement 34 to the EPU LAR (Reference 38). This license condition is addressed in SE Section 2.2.6.

In conjunction with the license amendment to revise paragraph 2.C.(1) of Renewed FOL No. DPR-68, for BFN Unit 3, to reflect the new maximum licensed reactor core power level of 3952 megawatts thermal (MWt), the license is also amended to add the following license condition.

(14) Potential Adverse Flow Effects

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) for initial power ascension from 3458 MWt to the extended power uprate (EPU) level of 3952 MWt.

(a) The following requirements are placed on operation of the facility before and during the initial power ascension to 3458 MWt:

1. TVA shall provide a Power Ascension Test (PAT) Plan for the BFN Unit 3 steam dryer testing. This plan shall include:

   a. Criteria for comparison and evaluation of projected strain and acceleration with on-dryer instrument data.

   b. Acceptance limits developed for each on-dryer strain gauge.

   c. Tables of predicted dryer stresses at a power level of 3458 MWt, strain amplitudes and power spectral densities (PSDs) at strain gauge locations, and maximum stresses and locations.

   The PAT plan shall provide correlations between measured strains and the corresponding maximum stresses. The PAT plan shall be submitted to the NRC Project Manager no later than 10 days before start-up.

2. TVA shall monitor the main steam line (MSL) strain gauges and on-dryer instrumentation at a minimum of three power levels up to 3458 MWt. Based on a comparison of projected and measured strains and accelerations, BFN will assess whether the dryer acoustic and structural models have adequately captured the response significant to peak stress projections. If the measured strains and accelerations are not within the 3458 MWt acceptance limits, the new measured data will be used to re-perform the full structural re-analysis for the purposes of generating modified EPU acceptance limits.

a. If the on-dryer instrumentation is unavailable, the BFN Unit 3 power ascension will be monitored using the available MSL strain gauges. The predicted dryer loads during the power ascension will be calculated with the Plant Based Load Evaluation (PBLE) Method 2 transfer function used in the steam dryer design analyses for EPU. The acceptance limits will ensure that the steam dryer stress margins remain above the final minimum alternating stress ratio (MASR) accepted in the EPU design analyses.

3. BFN shall provide a summary of the data and evaluation of predicted and measured pressures, strains, and accelerations at a power level of 3458 MWt. These data will include the BFN-specific bias and uncertainty data and transfer function, revised peak stress table and any revised acceptance limits. The predicted pressures shall include those using both PBLE methods (that is, Method 1 using on-dryer data, and Method 2 using MSL data). It shall be provided to the NRC Project Manager upon completion of the evaluation. TVA shall not increase power above 3458 MWt until the NRC Project Manager notifies TVA that NRC accepts the evaluation or NRC questions regarding the evaluation have been addressed. If no questions are identified within 240 hours after the NRC receives the evaluation, power ascension may continue.

a. If the on-dryer instrumentation is unavailable and the BFN-specific bias and uncertainty data and transfer function cannot be developed when BFN Unit 3 reaches a power level of 3458 MWt, the BFN Unit 3 power ascension above 3458 MWt will be monitored using the available MSL strain gauges. The predicted dryer loads during the power ascension will be calculated with the PBLE Method 2 transfer function used in the steam dryer design analyses for EPU. The acceptance limits will ensure that the steam dryer stress margins remain above the final MASR accepted in the EPU design analyses.

(b) The following requirements are placed on operation of the facility during the initial power ascension from 3458 MWt to the approved EPU power level of 3952 MWt:

1. At test increments that do not exceed 2.5 percent of 3458 MWt (approximately 86 MWt), TVA shall hold the facility at approximately steady state conditions and collect data from available MSL strain gauges and available on-dryer instrumentation. This data will be evaluated, including the comparison of measured dryer strains to acceptance limits and the comparison of predicted dryer loads based on MSL strain gauge data to acceptance limits. It will also be used to trend and project loads at the next test point and to EPU conditions to demonstrate margin for continued power ascension.

a. If the on-dryer instrumentation becomes unavailable during power ascension above 3458 MWt, the BFN Unit 3 power ascension above 3458 MWt will be monitored using the available MSL strain

gauges. The predicted dryer loads during the power ascension will be calculated with the BFN-specific PBLE Method 2 transfer function developed from the on-dryer instrumentation and MSL strain gauge data taken at the 3458 MWt hold point, the BFN-specific bias and uncertainty data, the revised peak stresses, and revised acceptance criteria developed in item (a)3 above. The acceptance limits will maintain the steam dryer stress margins above a MASR of 1.0.

2. Following the data collection and evaluation at the plateaus at approximately 3630 MWt, 3803 MWt, and 3952 MWt, TVA shall provide a summary of the data and the evaluation performed in item (b)1 above to the NRC Project Manager. TVA shall not increase power above these power levels for up to 96 hours after the NRC Project Manager confirms receipt of the summary, unless prior to expiration of the 96 hour period, the NRC Project Manager advises that the NRC staff has no objection to continuation of power ascension.

3. Should the measured strains on the dryer exceed the Level 1 acceptance limits, or alternatively if the dryer instrumentation is not available and the projected load on the dryer from the MSL strain gauge data exceeds the Level 1 acceptance limits, TVA shall return the facility to a power level at which the limits are not exceeded. TVA shall resolve the discrepancy, evaluate and document the continued structural integrity of the steam dryer, and provide that documentation to the NRC Project Manager prior to further increases in reactor power. TVA shall not increase power for up to 96 hours to allow for NRC review and approval of the information.

   a. In the event that acoustic signals (in MSL strain gauge signals) are identified that challenge the dryer acceptance limits during power ascension above 3458 MWt, TVA shall evaluate dryer loads, and stresses, including the effect of ±10 percent frequency shift, and re-establish the acceptance limits and determine whether there is margin for continued power ascension.

   b. During power ascension above 3458 MWt, if an engineering evaluation for the steam dryer is required because a Level 1 acceptance limit is exceeded, TVA shall perform the structural analysis using the Steam Dryer Report, Appendix A methods to address frequency uncertainties up to ±10 percent and assure that peak responses that fall within this uncertainty band are addressed.

4. a. Following the data collection and evaluation at the EPU power level, TVA shall provide a final load definition and stress report of the steam dryer, including the results of a complete re-analysis using the BFN-specific bias and uncertainties and transfer function, to the NRC. The BFN-specific bias and uncertainties summary shall include both PBLE Method 1 and Method 2. This report shall be submitted to the NRC within 90 days of the

completion of EPU power ascension testing for BFN Unit 3. Should the results of this stress analysis indicate the allowable stress in any part of the dryer is exceeded, TVA shall reduce power to a level at which the allowable stress is met, evaluate the dryer integrity, and assess any shortcomings in the predictive analysis. The results of this evaluation, including a recommended resolution of any identified issues and a demonstration of dryer integrity at EPU conditions, shall be provided to the NRC for review and approval prior to return to EPU conditions.

b. Within 30 days after completion of the core flow sweep test at EPU conditions to determine any compounding effect due to alignment of Vane Passing Frequency and Safety Relief Valve resonance frequencies, TVA shall provide the core flow sweep test results for NRC review.

5. Following the data collection and evaluation at the EPU power level, TVA shall provide a vibration summary report to the NRC. The summary report shall be submitted to the NRC within 90 days of the completion of EPU power ascension testing for BFN Unit 3. The vibration summary report shall include the information in items 5.a through 5.c, as follows:

a. Vibration data for piping and valve locations deemed prone to vibration and vibration monitoring locations identified in Attachment 45 to the EPU application dated September 21, 2015, including the identified locations associated with MSLs, Feedwater Lines, Safety Relief Valves and the Main Steam Isolation Valves.

b. An evaluation of the measured vibration data collected in item 5.a above compared against acceptance limits.

c. Vibration values and associated acceptance limits at approximately 3630 MWt, 3803 MWt, and 3952 MWt using the data collected in item 5.a, above.

(c) TVA shall prepare the EPU PAT plan to include the following.

1. Level 1 and Level 2 acceptance limits for on-dryer strain gauges and for projected dryer loads from MSL strain gauge data to be used up to 3952 MWt.

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

3. Activities to be accomplished during 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 TVA application and all supplements to the application in support of the EPU LAR pertaining to the steam dryer before power increase above 3458 MWt.

10. Identify the NRC Project Manager as the NRC point of contact for providing PAT plan information during power ascension.

11. Methodology for updating limit curves.

(d) The following key attributes of the PAT Plan shall not be made less restrictive without prior NRC approval.

1. During initial power ascension testing above 3458 MWt, each of the two hold points shall be at increments of approximately 5 percent of 3458 MWt.

2. Level 1 performance criteria.

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

Changes to other aspects of the PAT Plan may be made in accordance with the guidance of NEI 99-04, "Guidelines for Managing NRC Commitments," issued July 1999.

(e) During the first two scheduled refueling outages after reaching full EPU conditions, TVA shall conduct a visual inspection of all accessible, susceptible locations of the steam dryer in accordance with Boiling Water Reactor Vessels and Internals Project (BWRVIP)-139A (Steam Dryer Inspection and Flaw Evaluation Guidelines) and GE inspection guidelines (SIL [Services Information Letter] 644, BWR Steam Dryer Integrity).

(f) 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 to NRC within 90 days following startup from each of the first two respective refueling outages.

(g) 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.

This license condition described above shall expire: (1) upon satisfaction of the requirements in items (e) and (f) provided that a visual inspection of the steam dryer does not reveal any new unacceptable flaw(s) or unacceptable flaw growth that is caused by fatigue, and; (2) upon satisfaction of the requirements specified in item (g).

2.2.6.8.2 Unit 1 License Condition - Potential Adverse Flow Effects

The following would be added to the BFN Unit 1, Renewed FOL as license condition 2.C.(18) as shown in Supplement 34 to the EPU LAR (Reference 38). This license condition is addressed in SE Section 2.2.6.

In conjunction with the license amendment to revise paragraph 2.C.(1) of Renewed FOL No. DPR-33, for BFN, Unit 1, to reflect the new maximum licensed reactor core power level of 3952 megawatts thermal (MWt), the license is also amended to add the following license condition.

(18) Potential Adverse Flow Effects

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) for initial power ascension from 3458 MWt to the extended power uprate (EPU) level of 3952 MWt.

(a) The following requirements are placed on operation of the facility before and during the initial power ascension:

1. TVA shall provide a Power Ascension Test (PAT) Plan for the BFN Unit 1 steam dryer testing. The PAT plan shall be submitted to the NRC Project Manager no later than 10 days before startup.

2. TVA shall monitor the main steam line (MSL) strain gauges at a minimum of three power levels up to 3458 MWt. If the number of active MSL strain gauges is less than two strain gauges (180 degrees apart) at any of the eight MSL locations, TVA will stop power ascension and repair/replace the damaged strain gauges and only then resume power ascension.

3. At least 90 days prior to the start of the BFN Unit 1 EPU outage, TVA shall revise the BFN Unit 1 replacement steam dryer (RSD) analysis utilizing the BFN Unit 3 on-dryer strain gauge based end-to-end bias and uncertainties (B&U) at EPU conditions, and submit the information including the updated limit curves and a list of dominant frequencies for BFN Unit 1, to the NRC as a report in accordance with 10 CFR 50.4.

   a. If the on-dryer instrumentation was not available when BFN Unit 3 reached a power level of 3458 MWt and the BFN-specific B&U data and transfer function could not be developed, the predicted dryer loads during the BFN Unit 1 power ascension will be calculated with the Plant Based Load Evaluation Method 2 transfer function used in the steam dryer design analyses for EPU.

The acceptance limits will be based on BFN Unit 3 steam dryer confirmatory stress analysis results using the MSL strain gauge data collected at EPU conditions. The acceptance limits will ensure the steam dryer stress margins remain above the minimum alternating stress ratio (MASR) determined in the BFN Unit 3 steam dryer EPU confirmatory analyses.

4. TVA shall evaluate the BFN Unit 1 limit curves prepared in item (a)3 above based on new MSL strain gauge data collected following the BFN Unit 1 EPU outage at or near 3458 MWt. If the limit curves change, the new post-EPU outage limit curves shall be provided to the NRC Project Manager. TVA shall not increase power above 3458 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.

5. TVA shall monitor the MSL strain gauges during power ascension above 3458 MWt for increasing pressure fluctuations in the steam lines. Upon the initial increase of power above 3458 MWt until reaching 3952 MWt, TVA shall collect data from the MSL strain gauges at nominal 2.5 percent of 3458 MWt (approximately 86 MWt) increments and evaluate steam dryer performance based on this data.

6. During power ascension at each nominal 2.5 percent power level above 3458 MWt (approximately 86 MWt), TVA shall compare the MSL data to the approved limit curves based on end-to-end B&Us from the BFN Unit 3 benchmarking at EPU conditions and determine the MASR.

7. TVA shall hold the facility at approximately 3630 MWt and 3803 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.

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

   d. Evaluate the measured vibration data (collected in item 7.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, to the NRC Project Manager, upon completion of the evaluation for each of the hold points.

   f. TVA 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.

8. If any frequency peak from the MSL strain gauge data exceeds the Level 1 limit curves, TVA shall return the facility to a power level at which the limit curve is not exceeded. TVA shall resolve the discrepancy, evaluate and document the continued structural integrity of the steam dryer, and provide that documentation to the NRC Project Manager prior to further increases in reactor power. If a revised stress analysis is performed and new limit curves are developed, then TVA 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 item (b)1 below.

(b) TVA shall implement the following actions for the initial power ascension from 3458 MWt to 3952 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 3458 MWt, TVA 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 item (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 BFN Unit 3 EPU measurements.

   b. Use of scaling factors associated with all of the safety relief valve acoustic resonances as estimated in the predictive analysis or in-plant data acquired during power ascension.

2. After reaching 3952 MWt, TVA shall obtain measurements from the MSL strain gauges and establish the steam dryer flow-induced vibration load fatigue margin for the facility and update the steam dryer stress report. These data will be provided to the NRC staff as described below in item (e).

(c) TVA shall prepare the EPU PAT Plan to include the following.

1. The MSL strain gauge limit curves to be applied for evaluating steam dryer performance, based on end-to-end B&Us from BFN Unit 3 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. Identify the NRC Project Manager as the NRC point of contact for providing PAT plan information during power ascension.

10. Methodology for updating limit curves.

(d) The following key attributes of the PAT Plan shall not be made less restrictive without prior NRC approval:

1. During initial power ascension testing above 3458 MWt, each of the two hold points shall be at increments of approximately 5 percent of 3458 MWt.

2. Level 1 performance criteria.

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

Changes to other aspects of the PAT Plan may be made in accordance with the guidance of NEI 99-04, "Guidelines for Managing NRC Commitments," issued July 1999.

(e) Following the data collection and evaluation at the EPU power level, TVA shall provide 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 BFN Unit 3 benchmarking at EPU conditions. The report shall be submitted to NRC within 90 days of the completion of EPU power ascension testing for BFN Unit 1. Should the results of this stress analysis indicate the allowable stress in any part of the steam dryer is exceeded, TVA shall reduce power to a level at which the allowable stress is met, evaluate the steam dryer integrity, and assess any shortcomings in the predictive analysis. The results of this evaluation, including a recommended resolution of any identified issues and a demonstration of steam dryer integrity at EPU conditions, shall be provided to the NRC for review and approval prior to return to EPU conditions.

(f) Following the data collection and evaluation at the EPU power level, TVA shall provide a vibration summary report to the NRC. The summary report shall be submitted to the NRC within 90 days of the completion of EPU power ascension

testing for BFN Unit 1. The vibration summary report shall include the information in items (f)1 through (f)3, as follows:

1. Vibration data for piping and valve locations deemed prone to vibration and vibration monitoring locations identified in Attachment 45 to the EPU application dated September 21, 2015, including the identified locations associated with MSLs, Feedwater Lines, Safety Relief Valves and the Main Steam Isolation Valves.

2. An evaluation of the measured vibration data collected in item (f)1 above compared against acceptance limits.

3. Vibration values and associated acceptance limits at approximately 3630 MWt, 3803 MWt, and 3952 MWt using the data collected in item (f)1, above.

(g) 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 Boiling Water Reactor Vessels and Internals Project (BWRVIP)-139A (Steam Dryer Inspection and Flaw Evaluation Guidelines) and General Electric (GE) inspection guidelines (SIL 644, BWR Steam Dryer Integrity).

(h) 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 to the NRC within 90 days following startup from each of the first two respective refueling outages.

(i) 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 items (g) and (h), 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 item (i).

2.2.6.8.3 Unit 2 License Condition - Potential Adverse Flow Effects

The following would be added to the BFN, Unit 2, Renewed FOL as license condition 2.C.(18) as shown in Supplement 34 to the EPU LAR (Reference 38). This license condition is addressed in SE Section 2.2.6.

In conjunction with the license amendment to revise paragraph 2.C.(1) of Renewed Facility Operating License No. DPR-52, for Browns Ferry Nuclear Plant (BFN) Unit 2, to reflect the new maximum licensed reactor core power level of 3952 megawatts thermal (MWt), the license is also amended to add the following license condition.

(18) Potential Adverse Flow Effects

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) for initial power ascension from 3458 MWt to the EPU power level of 3952 MWt.

(a) The following requirements are placed on operation of the facility before and during the initial power ascension:

1. TVA shall provide a Power Ascension Test (PAT) Plan for the BFN Unit 2 steam dryer testing. The PAT plan shall be submitted to the NRC Project Manager no later than 10 days before start-up.

2. TVA shall monitor the main steam line (MSL) strain gauges at a minimum of three power levels up to 3458 MWt. If the number of active MSL strain gauges is less than two strain gauges (180 degrees apart) at any of the eight MSL locations, TVA will stop power ascension and repair/replace the damaged strain gauges and only then resume power ascension.

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

   a. If the on-dryer instrumentation was not available when BFN Unit 3 reached a power level of 3458 MWt and the BFN-specific bias and uncertainty (B&U) data and transfer function could not be developed, the predicted dryer loads during the BFN Unit 2 power ascension will be calculated with the Plant Based Load Evaluation Method 2 transfer function used in the steam dryer design analyses for EPU. The acceptance limits will be based on BFN Unit 3 steam dryer confirmatory stress analysis results using the MSL strain gauge data collected at EPU conditions. The acceptance limits will ensure the steam dryer stress margins remain above the minimum alternating stress ratio (MASR) determined in the BFN Unit 3 steam dryer EPU confirmatory analyses.

4. TVA shall evaluate the BFN Unit 2 limit curves prepared in item (a)3 above based on new MSL strain gauge data collected following the BFN Unit 2 EPU outage at or near 3458 MWt. If the limit curves change, the new post-EPU outage limit curves shall be provided to the NRC Project Manager. TVA shall not increase power above 3458 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.

5. TVA shall monitor the MSL strain gauges during power ascension above 3458 MWt for increasing pressure fluctuations in the steam lines. Upon the initial increase of power above 3458 MWt until reaching 3952 MWt, TVA shall collect data from the MSL strain gauges at nominal 2.5% of 3458 MWt (approximately 86 MWt) increments and evaluate steam dryer performance based on this data.

6. During power ascension at each nominal 2.5 percent power level above 3458 MWt (approximately 86 MWt), TVA shall compare the MSL data to the approved limit curves based on end-to-end B&Us from the BFN Unit 3 benchmarking at EPU conditions and determine the MASR.

7. TVA shall hold the facility at approximately 3630 MWt and 3803 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.

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

   d. Evaluate the measured vibration data (collected in item 7.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, to the NRC Project Manager, upon completion of the evaluation for each of the hold points.

   f. TVA 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.

8. If any frequency peak from the MSL strain gauge data exceeds the Level 1 limit curves, TVA shall return the facility to a power level at which the limit curve is not exceeded. TVA shall resolve the discrepancy, evaluate and document the continued structural integrity of the steam dryer, and provide that documentation to the NRC Project Manager prior to further increases in reactor power. If a revised stress analysis is performed and new limit curves are developed, then TVA 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 item (b)1 below.

(b) TVA shall implement the following actions for the initial power ascension from 3458 MWt to 3952 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 3458 MWt. TVA 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 item (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 BFN Unit 3 EPU measurements.

   b. Use of scaling factors associated with all of the SRV acoustic resonances as estimated in the predictive analysis or in-plant data acquired during power ascension.

2. After reaching 3952 MWt, TVA shall obtain measurements from the MSL strain gauges and establish the steam dryer flow-induced vibration load fatigue margin for the facility and update the steam dryer stress report. These data will be provided to the NRC staff as described below in item (e).

(c) TVA shall prepare the EPU PAT Plan to include the following.

1. The MSL strain gauge limit curves to be applied for evaluating steam dryer performance, based on end-to-end B&Us from BFN Unit 3 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 3458 MWt.

10. Identify the NRC Project Manager as the NRC point of contact for providing PAT plan information during power ascension.

11. Methodology for updating limit curves.

(d) The following key attributes of the PAT Plan shall not be made less restrictive without prior NRC approval:

1. During initial power ascension testing above 3458 MWt, each of the two hold points shall be at increments of approximately 5 percent of 3458 MWt.

2. Level 1 performance criteria.

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

Changes to other aspects of the PAT Plan may be made in accordance with the guidance of NEI 99-04, "Guidelines for Managing NRC Commitments," issued July 1999.

(e) Following the data collection and evaluation at the EPU power level, TVA shall provide 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 BFN Unit 3 benchmarking at EPU conditions. The report shall be submitted to NRC within 90 days of the completion of EPU power ascension testing for BFN Unit 2. Should the results of this stress analysis indicate the allowable stress in any part of the steam dryer is exceeded, TVA shall reduce power to a level at which the allowable stress is met, evaluate the steam dryer integrity, and assess any shortcomings in the predictive analysis. The results of this evaluation, including a recommended resolution of any identified issues and a demonstration of steam dryer integrity at EPU conditions, shall be provided to the NRC for review and approval prior to return to EPU conditions.

(f) Following the data collection and evaluation at the EPU power level, TVA shall provide a vibration summary report to the NRC. The summary report shall be submitted to the NRC within 90 days of the completion of EPU power ascension testing for BFN Unit 2. The vibration summary report shall include the information in items (f)1 through (f)3, as follows:

1. Vibration data for piping and valve locations deemed prone to vibration and vibration monitoring locations identified in Attachment 45 to the EPU application dated September 21, 2015, including the identified locations associated with MSLs, Feedwater Lines, Safety Relief Valves and the Main Steam Isolation Valves.

2. An evaluation of the measured vibration data collected in item (f)1 above compared against acceptance limits.

3. Vibration values and associated acceptance limits at approximately 3630 MWt, 3803 MWt, and 3952 MWt using the data collected in item f(1), above.

(g) 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 Boiling Water Reactor Vessels and Internals Project (BWRVIP)-139A (Steam Dryer Inspection and Flaw Evaluation Guidelines) and General Electric (GE) inspection guidelines (SIL 644, BWR Steam Dryer Integrity).

(h) 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.

(i) 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 items (g) and (h), 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 item (i).

The NRC staff reviewed the proposed license conditions for the replacement steam dryers of the three BFN Units and compared them with those for other plants that completed power ascension and implemented EPU.

2.2.6.8.4 Conclusion

The NRC staff concludes that the proposed license conditions are acceptable and provide reasonable assurance that the implementation of the EPU will maintain the current licensing basis of the Browns Ferry RSDs.

2.3 Electrical Engineering

2.3.1 Environmental Qualification of Electrical Equipment

Regulatory Evaluation

Environmental qualification (EQ) of electrical equipment involves demonstrating that the equipment is capable of performing its safety function under significant environmental stresses that could result from 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, "Environmental qualification of electric equipment important to safety for nuclear power plants," which sets forth requirements for the qualification of electrical equipment important to safety that is located in a harsh environment. Section 50.49(k) of 10 CFR states that the applicants for and holders of operating licenses are not required to requalify electric equipment important to safety in accordance with the provisions of this section if the Commission has previously required qualification of that equipment in accordance with the Division of Operating Reactor (DOR) guidelines, "Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors," November 1979 (Reference 150) or NUREG-0588 (for comment version), "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment" (Reference 151). Replacement equipment must be qualified in accordance with the provisions of 10 CFR Section 50.49 unless there are sound reasons to the contrary, as explained in RG 1.89 Regulatory Position C.6. Specific review criteria are contained in SRP Section 3.11.

Technical Evaluation

NUREG-0588 includes the NRC staff positions in two categories. Category I positions apply to equipment qualified in accordance with the Institute of Electrical and Electronics Engineers (IEEE) Standard (Std.) 323-1974, "IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations." NUREG-0588, Category II positions apply to equipment qualified in accordance with IEEE Std. 323-1971, "IEEE Trial-Use Standard: General Guide for Qualifying Class I Electric Equipment for Nuclear Power Generating Stations for Qualifying Class 1E Equipment for Nuclear Power Generating Stations." IEEE Std. 323-1974 recommends specific margins to be maintained for type testing that were not included in the IEEE 323-1971.

In the LAR (Reference 1), Attachment 6/7 (proprietary/non-proprietary versions of PUSAR), (Reference 47), Section 2.3.1, the licensee stated that safety-related electrical equipment in areas affected by EPU was reviewed consistent with the requirements of NUREG-0588 Category II, Division of Operating Reactors (DOR) guidelines of NRC Inspection and Enforcement (IE) Bulletin 79-01B, "Environmental Qualification of Class 1E Equipment" (Reference 152) or 10 CFR 50.49 (NUREG-0588 Category I), and RG 1.89, Revision 1, "Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants" (Reference 153) to ensure that the existing qualification for the normal and accident conditions expected in the areas where the devices are located remains adequate.

In its letters dated June 17 (Reference 22) and September 21, 2016 (Reference 34), in response to NRC staff RAIs, the licensee provided the current licensing basis (including the history) for the Browns Ferry EQ of electrical equipment. The licensee clarified that Browns Ferry has various EQ components which are qualified to DOR, or Category II of NUREG-0588, or 10 CFR 50.49. TVA treats NUREG-0588 Category I components the same as 10 CFR 50.49.

2.3.1.1 Inside Primary Containment

The licensee's EQ for safety-related electrical equipment located inside containment is based on steam line break (SLB) and/or DBA-LOCA conditions along with the temperature, pressure, humidity, and radiation consequences. The EQ for safety-related electrical equipment also includes the normal operating environments expected to exist during plant operation. The licensee identified no change in humidity due to the EPU because the Browns Ferry EQ program assumes saturated conditions for the duration of the LOCA/SLB event inside the primary containment. The changes identified in temperature, pressure, and radiation are discussed below:

Temperature:

In the PUSAR (Reference 37), the licensee provided the CLTP and EPU worst case drywell EQ accident temperature profiles (Figure 2.3-1), which were developed by combining the bounding curves for both the SLB and LOCA DBAs. The EPU profile for primary containment exceeds the existing drywell profile. In response to an NRC staff's question regarding the EQ of components in the drywell, the licensee in the letter dated June 17, 2016 (Reference 22), clarified that based on the result of the accident degradation equivalency (ADE) calculations, the individual component qualification testing temperature exceeds the EPU drywell accident temperature profile. The licensee stated that the ADE is an industry accepted method of comparing the test and plant accident temperature profiles to demonstrated acceptable post-accident qualification. The licensee provided the results of the ADE calculations and profiles for three worst case examples of environmentally qualified electrical equipment inside primary containment. The NRC staff reviewed the worst case profiles and finds that the component qualification test temperatures bound the EPU drywell accident temperature profile.

Regarding the temperature margins required by 10 CFR 50.49(e)(8), the licensee in the letter dated June 17, 2016 (in response to an NRC staff RAI) (Reference 22) clarified that the suggested temperature margins recommended by IEEE Std. 323-1974 were not applied to DOR electrical components because the DOR guidelines do not require explicit margins due to implicit conservatisms included in the guideline criteria. The licensee also stated that the IEEE Std. 323-1974 margins were not applied to NUREG-0588 Category II electrical components because the NUREG-0588 Category II qualification criteria are equivalent to the DOR guideline criteria, which do not require explicit margins. The NRC staff finds the licensee's response acceptable, since the NUREG-0588 Category II and DOR qualification criteria are equivalent and the DOR guidelines do not require explicit margins. For the NUREG-0588 Category I and 10 CFR 50.49 electrical components, the licensee verified that current component qualification temperature profiles provide the IEEE Std. 323-1974 suggested temperature margin (15 °F), or provided technical justifications why adequate temperature margin is maintained when the suggested temperature margins are not met. The staff reviewed the licensee's justifications and finds that peak temperature margins exist because the components' EQ test profiles peak temperatures remain above the EPU accident profiles peak temperatures for a considerably longer duration. In addition, according to RG 1.89 (Reference 153), quantified margins that are applied to the environmental parameters to ensure that the postulated accident conditions are enveloped during testing are acceptable alternatives to the IEEE Std. 323-1974 suggested margins. Since there are margins in the peak temperatures, the staff finds that, based on the recommendations of RG 1.89, the licensee's justifications for adequate margins are acceptable.

In the PUSAR, Section 2.3.1, the licensee stated that the maximum normal and maximum abnormal temperatures inside primary containment will increase by 0.12 °F (rounded to 1 °F) at EPU conditions. This small increase will have a minor effect on equipment thermal qualified life that will be addressed as part of normal equipment EQ maintenance replacement. In the letter dated June 17, 2016, in response to another NRC staff RAI, the licensee provided the EPU maximum normal and abnormal temperatures and the EQ maximum DBA temperature limits for electrical equipment inside the primary containment (Table EEEB-RAI 8-1). The licensee further stated that the EQ program maintenance and periodic replacement requirements will be changed, as required, to ensure that all 10 CFR 50.49 components remain qualified and capable of performing their intended design functions under EPU conditions. The NRC staff reviewed the response and finds that the EQ temperature limits for environmentally qualified electrical equipment inside the drywell bound the EPU maximum normal and abnormal temperatures with adequate margins.

Pressure:

In the LAR Attachment 6/7 (PUSAR), as updated by Enclosures 1 and 2 of the October 28, 2016, letter, Section 2.3.1, the licensee stated that the peak accident pressure increased from 50.64 psig to 50.9 psig at EPU conditions. The licensee provided the components' pressure qualification limits with associated margins, which was calculated with respect to the EPU peak accident pressure, in Table 2.3-2, "Evaluation of Pressure Qualification of EQ Components in the Drywell," of the LAR. The NRC staff reviewed the table and finds that components' qualification pressure limits bound the EPU peak accident pressure with margin greater than 10 percent.

Radiation:

In the updated PUSAR (Reference 37), the licensee stated that the total integrated doses (TID) (normal plus accident) for EPU conditions will increase by less than 16 percent above CLTP levels inside primary containment. The licensee provided the radiation qualification doses and the EPU TID for components located inside primary containment in Table 2.3-3, "Evaluation of Radiation Qualification of EQ components." The LAR Table 2.3-3 showed that the EPU TID exceeded the radiation qualification doses for some cables, solenoids, splices, and motor operated valves (MOVs). Note 3 of Table 2.3-3 stated that these components have limited life of less than 60 years due to EPU radiation, and they will be replaced periodically as part of the normal EQ maintenance program. In the June 17, 2016 letter (Reference 22), in response to the NRC staff's RAI, the licensee clarified that these components will be replaced once they operate up to the time when their normal dose limits equal their qualification test doses minus worst case accident doses. The staff finds that, since the components that have limited qualified life due to radiation aging at EPU conditions will be replaced as warranted by the Browns Ferry EQ program, the licensee has adequately addressed the effects of the increased radiation on components. The staff also verified that the radiation qualification doses for the EQ components, except those that have limited life due to radiation aging, exceeds the EPU TID, which means that these components remain qualified for post-EPU radiation levels.

Regarding radiation margins, Note 2 of Table 2.3-3 stated that no margin was added to the EPU TID because the Browns Ferry radiation parameters were calculated using methods of Appendix D to NUREG 0588, Revision 1 (Reference 151). In accordance with Section 1.4 of NUREG 0588, the additional radiation margins (10 percent) identified in IEEE Std. 323-1974 for qualification type testing are not required if the methods identified in Appendix D of

NUREG-0588 are used. Based on this information, the staff finds that no additional radiation margin is required for the Browns Ferry EPU TID.

In summary, the NRC staff finds that the EQ electrical components inside primary containment are capable of performing their functions at EPU conditions because the components' qualification parameters (i.e., temperature, pressure, humidity, and radiation) are adequate, and as such the components remained qualified for the EPU environmental conditions. The staff also finds that EQ components that have a limited qualified life due to thermal and radiation aging inside primary containment will be replaced in accordance with the Browns Ferry EQ program to ensure that these components remain environmentally qualified for EPU conditions.

2.3.1.2 Outside Primary Containment

The licensee's high-energy line break (HELB) analysis for the secondary containment evaluated numerous break locations and sizes occurring in the high pressure coolant injection (HPCI), reactor core isolation cooling (RCIC), reactor water cleanup (RWCU) and main steam/feedwater systems. The effect of operating at EPU conditions was evaluated based on the M&E releases and the analytical bases used in the Browns Ferry HELB analyses. The changes in temperature, pressure, humidity and radiation are discussed below.

Temperature:

In the LAR (Reference 1), the licensee determined that the RWCU HELB will change the peak temperature in some EQ rooms due to the EPU. The licensee provided a list of EQ components affected by the increase in RWCU HELB peak temperature and their temperature qualification limits. The staff noted that some EQ rooms identified in Table 2.3-1, "Summary of EPU Effect on EQ DBA Environmental Parameters," as having an increase in RWCU HELB peak temperature were not included in the list. The licensee in Table 2.3-1 also stated that all but a few EQ locations affected by LOCA will increase in temperature at EPU conditions. In the letter dated June 17, 2016 (Reference 22), in response to an RAI, the licensee provided the EPU RWCU HELB peak temperatures with the EQ components' qualification limits in all EQ rooms affected by the temperature increase (Table EEEB-RAI 9-1). The licensee also provided the EPU LOCA peak temperatures with the EQ components' qualification limits in the affected EQ rooms (Table EEEB-RAI 9-2). The NRC staff reviewed the information provided and finds that the component qualification temperature limits bound the peak HELB and LOCA accident temperatures with adequate margins at EPU conditions in all EQ rooms except EQ Room 16. In EQ Room 16 (RWCU backwash receiving tank room), the EPU peak accident temperature (215 °F) in BFN Unit 2 exceeds the qualification temperature limit (205 °F) for cables for approximately 60 seconds. The licensee in Note 3 of Table 2.3-5, "RWCU LOCA/HELB Temperature Evaluation outside Containment," of the PUSAR states: "DOR cable [cable that is qualified in accordance with DOR guidance] is worst case limited to 205 °F long term peak temperature but may exceed 205 °F for approximately 10 minutes as long as it is under a maximum temperature of 300 °F" (Reference 154). According to this referenced NRC letter, the use of the DOR guidelines for EQ of BFN Unit 2 cables is "based on the understanding that temperatures and times during which an ambient temperature of 205 °F would be exceeded were of a relatively short duration (approximately 10 minutes) and under a maximum temperature of 300 °F." Based on the May 11, 1989 letter, the NRC staff finds the BFN Unit 2 cable qualification temperature in EQ Room 16 acceptable because the EPU peak accident

temperature (215 °F), which the DOR cables are exposed to, is less than 300 °F and the exposure time is less than 10 minutes.

In the LAR, the licensee stated that the main steam valve vault (EQ Room 7) bulk temperature will increase by 0.37 °F (rounded up to 1 °F) at EPU conditions. The licensee also stated that the temperature increase has a minor effect on thermal qualified life and is addressed as part of normal EQ maintenance replacement. In the letter dated June 17, 2016 (Reference 22), in response to an RAI, the licensee provided EPU maximum normal and abnormal temperatures and the EQ maximum DBA temperature limits for electrical equipment in the main steam valve vault (Table EEEB-RAI 8-2). The licensee further stated that the EQ program maintenance and periodic replacement requirements will be changed, as required, to ensure that all 10 CFR 50.49 components remain qualified and capable of performing their intended designed function under EPU conditions. The NRC staff reviewed the response and finds that the EQ temperature limits for electrical equipment outside primary containment bound the EPU maximum normal and abnormal temperatures with adequate margins.

Pressure:

In the letter dated June 17, 2016 (Reference 22), in response to the staff RAI, the licensee stated that the RWCU and MS/feedwater HELBs pressures were impacted by the EPU. The licensee provided the RWCU HELB and MS/feedwater HELB peak pressures for CLTP and EPU conditions (Tables EEEB-RAI 11-1, 11-2), and the qualification pressure of EQ components (Table EEEB RAI 11-3) in all EQ rooms affected by the HELBs events. The NRC staff reviewed the tables and finds that the components' qualification peak pressures bound the EPU HELB peak pressures with adequate margins for the affected EQ rooms.

Radiation:

In the LAR, the licensee stated that the TID (normal plus accident) for EPU conditions will generally increase by less than 20 percent above CLTP levels outside primary containment for components with a few areas greater than 20 percent due to EPU dose rate increases. The licensee provided the radiation qualification doses and the EPU TID located outside primary containment in Table 2.3-3 of the PUSAR. The licensee in Table 2.3-3 showed that the radiation qualification doses for some cables, solenoids, splices, and MOVs located in some areas outside the primary containment are less than the EPU TID in those areas. Note 3 of Table 2.3-3 stated that these components have limited life of less than 60 years due to EPU radiation, and they will be replaced periodically as part of the normal EQ maintenance program. In the June 17, 2016 letter, in response to an NRC staff RAI, the licensee clarified that these components will be replaced once they operate up to the time when their normal dose limit equals the qualification test dose minus worst case accident dose. The NRC staff finds that, since the components that have limited qualified life due to radiation aging at EPU conditions will be replaced as warranted by the Browns Ferry EQ program, the licensee has adequately addressed the effects of the increased radiation on components. The staff also verified that the qualification doses for the remaining EQ components exceeds the EPU TID, which means that these components will remain qualified for post-EPU radiation level for 60 years of licensed operation.

Regarding radiation margins, Note 2 of Table 2.3-3 stated that no margin was added to the EPU TID because the Browns Ferry radiation parameters were calculated using methods of Appendix D to NUREG 0588, Revision 1. In accordance with Section 1.4 of NUREG 0588, the

additional radiation margins (10 percent) identified in IEEE Std. 323-1974 for qualification type testing are not required if the methods identified in Appendix D of NUREG-0588 are used. Based on this information, the NRC staff finds that no additional radiation margin is required for the Browns Ferry EPU TID.

Humidity:

In the PUSAR Section 2.3.1, the licensee stated that the Browns Ferry EQ program does not assume saturated conditions for the duration for the HELB event outside primary containment. The licensee further stated that the period for 100 percent relative humidity conditions following an RWCU HELB for affected reactor building areas will increase to four hours at EPU conditions. However, this increased period at 100 percent relative humidity does not exceed the post-accident conditions for which the affected safety-related electrical equipment is qualified. Based on this information, the NRC staff finds that the safety-related equipment located in the above-mentioned areas will not be negatively impacted by the increased period of 100 percent relative humidity.

In summary, the NRC staff finds that the EQ electrical components outside primary containment are capable of performing their safety functions at EPU conditions because the components' qualification parameters (i.e., temperature, pressure, radiation, and humidity) are adequate, and as such the components remained qualified for the EPU environmental conditions. The staff also finds that EQ components that have a limited qualified life due to thermal or radiation aging outside primary containment will be replaced in accordance with the Browns Ferry EQ program to ensure that these components remain environmentally qualified for EPU conditions.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the EQ of electrical equipment and concludes that the licensee has adequately addressed the effects of the proposed EPU on the environmental conditions inside and outside primary containment 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. Draft GDC-24, "Emergency Power for Protection Systems," states: "In the event of loss of all offsite power, sufficient alternate sources of power shall be provided to permit the required functioning of the protection systems." Draft GDC-39, "Emergency Power for Engineered Safety Features," states: "Alternate power systems shall be provided and designed with adequate independency, redundancy, capacity, and testability to permit the functioning required of the engineered safety features. As a minimum, the onsite power system and the offsite power system shall each, independently, provide this capacity assuming a failure of a single active component in each power system."

Furthermore, according to the Browns Ferry UFSAR Section 8.3, "Transmission System," Browns Ferry meets the requirements of 10 CFR Part 50, Appendix A, GDC-17 regarding the capacity and capability requirements of offsite power sources. 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

According to the Browns Ferry UFSAR Section 8.3, the BFN Units 1, 2, and 3 main generators are connected to an existing network supplying large load centers. All three units are tied into TVA's 500-kilovolts (KV) transmission system via seven 500-KV transmission lines. The 161 KV switchyard is supplied by two 161-KV transmission lines. The 500-KV and 161-KV switchyards supply startup, running, and shutdown power through stepdown transformers. The 161-KV switchyard also supplies the cooling tower power.

The 500-KV switchyard serves to receive the output of the station's Units 1, 2, and 3 generators and delivers it to the 500-KV system network for transmission to system loads. The 500-KV switchyard also serves as an offsite power source for plant auxiliary power distribution systems. Power to each unit's auxiliary loads is back-fed from the 500-KV system through main transformers and unit station service transformers (USSTs), when the associated main generator is offline. When the main generator is online, the main generator provides the unit's auxiliary load through the USSTs.

The 161-KV switchyard receives power from the 161-KV system network and delivers this power to station auxiliaries through two common station service transformers (CSSTs) for Units 1, 2, and 3 and cooling tower transformers (CTTs). In the LAR, the licensee stated that the 161-KV circuit connected to CSSTs can be credited as a qualified alternate offsite circuit for multiple units. Access to the 161-KV circuit requires a delayed manual transfer when operators can manually control the loads on the 4.16-KV start buses to support long term post-accident or transient recovery and shutdown.

As stated in the PUSAR Section 2.3.2.2, the licensee owns and operates both the transmission system and BFN Units 1, 2, and 3. The Browns Ferry offsite power system is part of the transmission system. The operation and maintenance of the offsite power system is under the control of the TVA transmission power systems organization. TVA performed transmission system studies to evaluate the adequacy of the Browns Ferry offsite power system to support operation at EPU conditions and the effects of Browns Ferry EPU on the transmission system.

The NRC staff evaluated the offsite power system and its components in the following subsections to ensure that they are capable of performing their intended functions at EPU conditions.

2.3.2.1 Grid Stability

In its letter dated January 20, 2017 (Reference 39), Enclosure 1, the licensee provided the interconnection System Impact Study (SIS), Revision 3. **[[**

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The above-mentioned transmission system upgrades resulting from the reactive power and transient stability analyses of the SIS were further evaluated for impacts on the Browns Ferry offsite power system in the Transmission System Stability Evaluation.

In Attachment 43 of the LAR dated September 21, 2015 (Reference 1), the licensee provided "Transmission System Stability Evaluation," which described the results of the Browns Ferry Transmission System Study (TSS)-Grid Voltage Study to evaluate the impact of the Browns Ferry EPU with respect to meeting the capacity and capability of requirements of 10 CFR Part 50 Appendix A, GDC-17. In its letter dated January 20, 2017 (Reference 39), Enclosure 2, the licensee provided an update of the Transmission System Stability Evaluation, Revision 4. [[

]] In the letter dated June 17, 2016 (Reference 22), in response to an NRC staff RAI, the licensee clarified that [[

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Planned maintenance or forced outages can impact the adequacy of the Browns Ferry offsite power system. [[

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In its letter dated January 20, 2017, Enclosure 3, in Revision 2 of its response to EEEB-RAI 1, the licensee provided [[

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The licensee also provided in the January 20, 2017 letter, [[

]]. In response to EEEB-RAI 17, the licensee in its letter dated June 17, 2016, provided the simulated voltage responses for the loss of the most critical 161-KV transmission line with one-, two-, and three-unit operations as pre-events for the immediate and delayed 161-KV sources. The licensee also clarified that the 161-KV offsite power system is qualified as an alternate immediate offsite power supply for BFN Unit 3 only, but all three BFN units may rely on the 161-KV system as a delayed offsite power source. The NRC staff reviewed the voltage responses and finds that the 161-KV offsite power source met the voltage drop acceptance criteria considered for the voltage analysis for the loss of the transmission line pre-event outage.

In its letter dated January 20, 2017, Enclosure 2, Section 4, the licensee provided a summary of the impact of the transmission system upgrades identified by the SIS on the results of the TSS. [[

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In its letter dated January 20, 2017, Enclosure 7, the licensee stated that the [[

]] In its letter dated May 27, 2016, Enclosure 5, the licensee stated that [[

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In its letter dated January 20, 2017, Enclosure 3, in response to EEEB-RAI 1 (Revision 2), the licensee provided [[

]].

In conclusion, based on the results of the SIS and the TSS, the NRC staff finds that the grid is capable of providing adequate capacity and capability with the transmission upgrades to meet GDC 17 under EPU conditions since 1) the simulated 500-KV and 161-KV bus voltages post DBE met the Browns Ferry minimum switchyard voltage requirements to provide adequate voltage to downstream safety-related equipment and 2) no reactive power and transient stability issues exist with the transmission system upgrades. The NRC staff also finds that the impact of Browns Ferry operation on grid stability under EPU conditions has been adequately analyzed.

2.3.2.2 Switchyard Components

500-KV switchyard

In the PUSAR Section 3.2.2, the licensee stated that the existing 500-KV switchyard components (i.e., bus, breakers, switches, transformers, and lines) are adequate for the increased generator output associated with the EPU. In response to an NRC staff RAI, the

licensee in its letter dated June 17, 2016 (Reference 22), provided the ratings, EPU duties/loadings, and margins for the 500-KV electrical equipment including components from the high side of the main power transformers (MPTs) to the 500-KV switchyard (busbars, disconnect switches, and circuit breakers) (Table EEEB-RAI 14-1). The licensee stated that the EPU loadings are based on the generator output at minimum system voltage (495 KV) with no house (onsite auxiliary) loads deducted to provide high duty loadings. The NRC staff reviewed the information and finds that the above-mentioned 500-KV electrical equipment is adequately rated to support operation at EPU conditions since the EPU duties are within the ratings of the equipment. The licensee also provided the ratings only for the transmission lines with their most limiting buswork elements associated with the 500-KV switchyard. The licensee stated that the transmission line components are adequately rated for the worst case conditions at EPU because the SIS identified no overload conditions for the most limiting component in the Browns Ferry 500-KV switchyard for the worst case transmission system configurations and loading conditions at EPU. Based on this information, the staff finds that the ratings of the transmission line components associated with the 500-KV switchyard are adequate for EPU operation.

161-KV switchyard:

In its letter dated June 17, 2016, in response to a NRC staff RAI, the licensee provided the ratings, EPU duties, and margins for the 161-KV offsite electrical equipment (Table EEEB-RAI 14-2). The licensee stated that the duties are based on the maximum allowable load on the CSSTs with the 161-KV system as a delayed source, plus the load expected from the CTTs, using the minimum system voltage that qualifies as a delayed source (157-KV) to maximize the duty loading. The staff reviewed the information and finds that the above-mentioned 161-KV offsite electrical equipment is adequately rated to support operation at EPU conditions since the EPU duties for the equipment are within the ratings of the equipment.

2.3.2.3 Main Generator

In the PUSAR Section 2.3.2, the licensee stated that the maximum ratings of the rewound main generators are 1,330 megavolts amperes (MVA) for Unit 1 and 1,332 MVA for Units 2 and 3. In its letter dated January 20, 2017, Enclosure 2, Section 3.1 of the Transmission System Stability Evaluation, Revision 4, the licensee stated [[

]]. In its letter dated February 16, 2016, Enclosure 5, in response to EEEB-RAI 3, the licensee stated that [[

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In the PUSAR Section 2.3.2, the licensee stated that no changes are required for the protective relaying for the main generators for operation at EPU conditions. In its letter dated June 17, 2016, in response to an NRC staff RAI, the licensee provided a summary of the evaluation for the adequacy of the existing settings for the protective relays described in Browns Ferry UFSAR Section 8.2, "Generators," for the rewound generators. The staff reviewed the licensee's evaluation and finds that the existing settings for the Browns Ferry above-mentioned protective relays for the main generators are adequate to protect the rewound generators since the settings are not impacted by the increase in MVA of the main generators. In the February 16, 2016 (Reference 6), letter, in response to an NRC staff RAI, the licensee stated that changes to increase the main generator H_2 pressure will include a change to the generator field over-excitation relay settings. This change will be completed prior to the EPU implementation at each of the BFN units.

In conclusion, the NRC staff finds that after implementation of the proposed modifications (changes to the generator H_2 pressure (including generator field over-excitation relay settings) and the generator excitation systems and installation of the SVC) the main generators will be adequate to support safe operation at EPU conditions since 1) the main generators ratings will be adequate to support the units increased electrical outputs, and 2) the main generators will remain stable during faults on the transmission lines.

2.3.2.4 Isolated Phase Bus Duct

In the PUSAR Section 2.3.2, the licensee stated that all three BFN units isolated phase bus (IPB) duct work, cooling coils and fans have been modified to increase the continuous current rating to support operation at EPU conditions. Table 2.3-6, "Offsite Electrical Equipment Ratings and Margins," of the PUSAR indicated that the IPB rating is 36,740 amperes for Unit 1 and 36,796 amperes for Units 2 and 3 at EPU operation. The licensee in its letter dated February 16, 2016 (Reference 6), Enclosure 5, in response to an NRC staff RAI, provided the IPB ducts required continuous current at 34,903 amperes for Unit 1 and 34,956 amperes for Units 2 and 3 for EPU conditions. The NRC staff finds that, since the IPB duct current ratings bound the IPB duct continuous current requirements, the IPB duct ratings are adequate to support safe operation under EPU conditions.

2.3.2.5 Generator Main Step-Up Main Power Transformers

In the PUSAR Section 2.3.2, the licensee stated that the main generator step-up MPTs for all three BFN units have been replaced and upgraded to support the increase in generator output. The MPTs are rated 1,500 MVA for Units 1, 2, and 3. Table 2.3-6 of the LAR indicates the EPU duties for the MPTs are 1,280 MVA for Unit 1 and 1,282 MVA for Units 2 and 3 based on a maximum generator output (i.e., 1,330 MVA for Unit 1 and 1,332 MVA for Units 2 and 3) minus auxiliary loads of 50 MVA. The NRC staff finds that, since the MPTs EPU duties are within the ratings of the MPTs, the MPT ratings are adequate to support safe operation under EPU conditions.

In its letter dated June 17, 2016, in response to an NRC staff RAI, the licensee stated that the variable percentage differential relays with harmonic-restraint for the MPTs are currently set to operate at EPU conditions. Based on this information, the staff finds that the relays settings for the MPTs are adequate for EPU operation.

2.3.2.6 Common Station Service Transformers

In the PUSAR Section 2.3, the licensee provided the ratings of the CSSTs along with their EPU duties based on CSST maximum shutdown loadings at EPU conditions in Table 2.3-6 of the PUSAR. Based on its review, the staff finds that the EPU duties/loadings for the CSSTs (36.15 MVA) are less than the CSSTs maximum (force oil-air ratings (36.5 MVA), and thus the CSSTs are adequately rated to support safe shutdown operation at EPU conditions.

In its letter dated June 17, 2016 (Reference 22), in response to an NRC staff RAI, the licensee stated that the CSSTs have zero loading during normal operations. Browns Ferry UFSAR Section 8.4, "Normal Auxiliary Power System," stated that that the Unit 1 or Unit 2 safety-related loads are not allowed to automatically transfer to the CSSTs. Therefore, the 161-KV offsite circuits via the CSSTs are not available to mitigate the immediate consequences of a LOCA on Unit 1 or 2. Concerning Unit 3, the 4-KV unit boards with their connected shutdown boards (both the safety-related and non-safety-related loads) are automatically transferred to the CSSTs upon failure of the preferred offsite power circuit from the 500-KV switchyard to the main power transformer. If this supply is unavailable, the safety-related 4-KV shutdown boards are automatically transferred to the standby (onsite) electric power sources. For Unit 1, 2, or 3, the 161-KV supplied CSSTs can be credited as qualified alternate offsite circuits. However, access to the alternate 161-KV offsite circuits will require a delayed manual transfer when operators can manually control the loads on the 4-KV start buses to support long term post-accident recovery and shutdown. Since the plant loads are transferred to the 161-KV offsite circuits via the CSSTs when the preferred offsite power circuit from the 500-KV is unavailable, the NRC staff finds that the CSSTs are not normally loaded.

In its letter dated January 20, 2017 (Reference 39), Enclosure 3, in response to an NRC staff RAI (Revision 2), the licensee also provided worst case loadings of CSSTs when the 161-KV offsite power source is considered an alternate immediate source (Unit 3 only) and an alternate delayed source (Units 1, 2, and 3). The staff finds that the CSST loadings remain within the CSSTs' ratings, and therefore, the CSST ratings remain adequate at EPU conditions.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the offsite power system and finds that the offsite power system has adequate capacity and capability to supply power to all safety loads and other required equipment. The NRC staff concludes that the offsite power system will continue to meet the draft GDC-24 and 39, and the capacity and capability requirements of GDC-17, following implementation of the proposed EPU. The NRC staff further concludes that the proposed EPU will have a negligible impact on the grid stability after modifications, as discussed in Section 2.3.2.1, "Grid Stability," of this report, are implemented. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the offsite power system.

2.3.3 Alternating Current (AC) Onsite Power System

Regulatory Evaluation

The AC onsite power system includes those standby power sources, distribution systems, and auxiliary supporting systems provided to supply power to safety-related equipment. The NRC staff's review covered the descriptive information, analyses, and referenced documents for the

AC onsite power system. According to the BFN UFSAR, Appendix A, Browns Ferry conforms to the intent of the draft GDC 24 and 39 dated July 10, 1967, for Nuclear Power Plant Construction regarding electrical power systems. Draft GDC-24, "Emergency Power for Protection Systems," states: "In the event of loss of all offsite power, sufficient alternate sources of power shall be provided to permit the required functioning of the protection systems." According to BFN UFSAR, Appendix A Draft GDC-39, "Emergency Power for Engineered Safety Features," states: "Alternate power systems shall be provided and designed with adequate independency, redundancy, capacity, and testability to permit the functioning required of the engineered safety features. As a minimum, the onsite power system and the offsite power system shall each, independently, provide this capacity assuming a failure of a single active component in each power system." In addition, in Section 8.4 of the Browns Ferry UFSAR, the licensee stated that Browns Ferry also meets the independence and redundancy requirements of GDC-17. Specific review criteria are contained in SRP Sections 8.1 and 8.3.1.

Technical Evaluation

The AC onsite power system consists of equipment and systems required to provide AC power to safety-related and non-safety-related loads as long as offsite power is available. The equipment and systems include 500 KV transformers (MPTs), 161-KV transformers (CSSTs), 22-KV transformers (USSTs), 4.16-KV transformers, 480-V transformers, 480-V load centers and motor control centers, 120/208-V distribution panels, and uninterruptible power supply systems.

The AC onsite power system also includes the standby power for safety-related unit functions from onsite standby emergency diesel generators (EDGs). The licensee stated that no changes are required to the EDGs' load or load sequencing for EPU operation.

The licensee stated that the AC onsite power distribution systems loads were reviewed under both normal and abnormal operating scenarios. The significant changes in electrical load demand are associated with increasing the size of the condensate pumps and condensate booster pumps to restore hydraulic margin. The licensee also stated that no electrical distribution system modifications are required for operation at the EPU power level because sufficient margin is available.

The staff reviewed the LAR to determine whether the above-mentioned AC onsite distribution equipment and systems are capable of performing their intended functions at EPU conditions. The 500-KV MPTs and the 161-KV CSSTs are evaluated in Section 2.3.2, "Offsite Power System," of this report. The NRC staff evaluation for the remaining above-mentioned onsite AC equipment and systems are discussed below.

2.3.3.1 Unit Station Service Transformers:

The USSTs supply normal power to the 4.16-KV unit boards for all three BFN units. In its letter dated June 17, 2016 (Reference 22), in response to an NRC staff RAI, the licensee provided the normal operating loadings and the worst case loadings under shutdown/accidents conditions for the USSTs at EPU operations (Tables EEEB-RAI 12-1 and EEEB-RAI 12-2). The NRC staff reviewed the loading data and finds that the EPU loadings are within the maximum ratings of the USSTs, and as such, the USSTs are adequately sized with margins to support operation at EPU conditions during normal and accident conditions.

2.3.3.2 4.16-KV Components

The 4.16-KV distribution equipment includes the 4.16-KV transformers, the 4.16-KV unit boards, 4.16-KV common boards, and 4.16-KV shutdown boards. The 4.16-KV transformers are on the secondary side of the CSSTs and USSTs. The NRC staff evaluations for the CSSTs and USSTs are provided in Section 2.3.2.6, "Common Station Service Transformers," and Section 2.3.3.1, "Unit Station Service Transformers," respectively, of this SE.

The 4.16-KV unit boards supply power to the balance of plant (BOP) and the safety-related shutdown buses. In the PUSAR Section 2.3.3, the licensee stated that the size of the BOP 4.16-KV condensate pumps (CPs) and condensate booster pumps (CBPs) have been increased to improve hydraulic margin for EPU operation. PUSAR Table 2.3-7, "Electrical Distribution System Load Changes," of the LAR shows that the maximum transient load on the CBPs is 3,720 brake horsepower assuming a trip of one out of three CBPs or CPs. This indicates an overload of the CBPs during the transient when compared to the nameplate rating of 3,000 HP for the CBPs. In its letter dated September 21, 2016 (Reference 34), in response to an NRC staff RAI (Revision 1) regarding the overload, the licensee clarified that the overload conditions (i.e., 3,720 BHP) for the CBPs are from system hydraulic analyses that were designed to maximize the loading of the BFN unit boards. The licensee further stated that the actual maximum CBP BHP upon trip of a CBP at EPU rated thermal power is 3,377 HP, which is within the 1.15 service factor (SF) rating of the motor (3,450 HP). Furthermore, upon a trip of a CBP, operators will take actions to prevent exceeding the pump motor winding temperature alarm of 266 °F. The licensee also provided the ratings and the worst case loading (maximum LOCA loads) for the 4.16-KV unit boards (Table EEEB-RAI 18-2), and a summary of the calculation for the CBP relay settings and coordination with the unit boards' feeder breakers. The staff reviewed the information provided and finds that 1) the above-mentioned overload of the CBP at EPU conditions is not an issue and results in conservative results since the actual CBP BHP upon trip of a CBP is within the SF rating of the CBPs, 2) the unit boards are rated to support operation at EPU conditions as the board maximum worst case loadings are within the ratings of the boards, and 3) the CBPs and their associated 4.16-KV unit boards are adequately protected against an overload during the transient since the calculation shows that the breakers' overcurrent relay settings are acceptable.

In its letter dated June 17, 2016, the licensee provided the ratings and worst case EPU loadings under accident/shutdown conditions for the 4.16-KV common boards and 4.16-KV shutdown boards (Table EEEB-RAI 19-1). The staff reviewed the loading information pertaining to the 4.16-KV distribution boards in the table and finds that the 4.16-KV common and shutdown boards are adequately sized to support operation at EPU conditions since the ampere rating of each board is greater than its associated worst case EPU loading.

The 4.16-KV shutdown boards are provided with degraded voltage protection. In its letter dated September 21, 2016 (Revision 1), Enclosure 1, in response to an NRC staff RAI, the licensee provided a summary of the degraded voltage analysis corresponding to EPU conditions. The licensee stated that the ratings and expected load profile of the safety-related equipment is unchanged, and as such, the existing Browns Ferry degraded voltage (DV) analysis still applies at EPU conditions. In the analysis, the adequacy of the onsite electrical voltage levels and the degraded voltage relay settings are evaluated at EPU conditions. This analysis involved the calculation of boards and loads voltages assuming a 4.16-KV shutdown boards operation at the DV dropout voltage (3900 volts (V)) and at reset voltage (3983 V) for a worst case LOCA

loading for a time duration of 60 seconds. Also, the voltage versus time graphs for the 4.16-KV shutdown boards assuming a 495-KV starting yard voltage, a LOCA on Unit 1, and offsite power available, for the first 60+ seconds of the event, are provided in the summary. The staff reviewed the summary of the analysis and finds that the safety-related boards and loads will perform their functions under DV conditions at EPU operation since 1) the shutdown boards met the minimum required voltages, 2) the running and starting voltages of the safety-related loads required to mitigate an accident are either within the acceptable values or found acceptable based on the characteristics of the loads, and 3) the shutdown boards bus voltages recover within the DV relay reset time delays of 6.9 seconds. Therefore, the staff finds that the existing DV relay settings are adequate for EPU operation.

2.3.3.3 480-V Components

In its letter dated June 17, 2016, in response to EEEB-RAI 19, the licensee provided the worst case loading on the 480-V distribution equipment (boards and transformers) under accidents/shutdown conditions at both CLTP and EPU conditions (Table EEEB-RAI 19-1). The staff verified that the EPU loadings for the 480-V boards and transformers are within the ampere ratings of the boards/transformers with acceptable margins. The staff therefore determined that the 480-V equipment is adequate to support safe operation at EPU conditions.

2.3.3.4 120-V AC distribution systems

In its letter dated June 17, 2016, in response to EEEB-RAI 19, the licensee provided the rating and the steady state loadings for the following 120-V AC distribution systems at EPU conditions (Table EEEB-RAI 19-2): the 120-V AC Instrument and Control (I&C) Power System, the Reactor Protection System (RPS), and the 120-V AC unit preferred system including the uninterruptible power supply system. The licensee stated that the EPU data for these systems are based on existing nameplate data, and the loadings for these systems do not change as a result of the EPU. The NRC staff verified that the EPU loadings for the buses in each of the above-mentioned 120-V AC system are within the ratings of the buses with acceptable margins. The NRC staff therefore determined that the 120-V AC distribution systems (I&C system, RPS, and unit preferred system) are adequate to support operation at EPU conditions.

Conclusion

The NRC staff 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 draft GDC-24 and 39 following implementation of the proposed EPU. The onsite power system has capacity and capability to supply power to all safety loads and other required equipment for EPU operations. The NRC staff also finds that Browns Ferry will continue to meet the independence and redundancy requirements of GDC-17 since no changes were made to these requirements for EPU operations. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the AC onsite power system.

2.3.4 DC Onsite Power System

Regulatory Evaluation

The direct current (DC) onsite power system includes the DC power sources and their distribution and auxiliary supporting systems that are provided to supply motive or control power to safety-related equipment. The NRC staff's review covered the information, analyses, and referenced documents for the DC onsite power system. Draft GDC-24, "Emergency Power for Protection Systems," states: "In the event of loss of all offsite power, sufficient alternate sources of power shall be provided to permit the required functioning of the protection systems. Draft GDC-39, "Emergency Power for Engineered Safety Features" states: "Alternate power systems shall be provided and designed with adequate independency, redundancy, capacity, and testability to permit the functioning required of the engineered safety features. As a minimum, the onsite power system and the offsite power system shall each, independently, provide this capacity assuming a failure of a single active component in each power system." Specific review criteria are contained in SRP Sections 8.1 and 8.3.2.

In PUSAR Section 2.3, the licensee stated that the 1967 AEC proposed GDC or draft GDC-24 and 39 are applicable to the Browns Ferry onsite DC power systems. The NRC staff requested the licensee to explain the applicability of final GDC-17 to the Browns Ferry DC power systems. In its letter dated June 17, 2016, the licensee clarified that the Browns Ferry DC electrical power system is also designed to have sufficient independence, redundancy, and testability to perform its safety functions, assuming a single failure, as required by 10 CFR Part 50, Appendix A, GDC-17.

Technical Evaluation

Browns Ferry UFSAR Section 8.6, "250-V DC Power Supply and Distribution," stated that the engineered safeguards system 250-V DC power system includes a 250-V DC unit system and a 250-V DC control power supply system. The 250-V DC unit system includes three unit batteries, and the 250-V DC control power supply system includes five shutdown batteries. The unit and shutdown batteries supply the engineered safeguards system loads (safety-related loads) and some non-safety related loads.

In the June 17, 2016 letter, in response to an NRC staff RAI, the licensee stated that the non-safety related loads have increased by 0.3 amps when the relays for the replacement MPTs changed to micro-processor based relays for the EPU, and the existing 250-V DC battery sizing calculation is adequate to support the current load profile of each battery.

In response to an NRC staff RAI (Revision 1), the licensee provided in the September 21, 2016 (Reference 34), letter a summary of the 250-V DC batteries (unit and shutdown) sizing calculation for LOCA/loss-of-offsite power (LOOP) scenarios corresponding to EPU conditions. The summary included the acceptance criteria, the analysis, and the results of the calculations. The scenario assumed a DBA in one unit, a spurious DBA (LOCA) in another unit, and a LOOP with one battery system out of service and the safe shutdown and cooldown of the remaining non-DBA unit. The batteries have 30-minute duty cycles. The NRC staff reviewed the summary of the calculations and finds that the calculated voltages met the boards' minimum acceptable voltages (210-V) required to ensure the proper functioning of the most limiting load on each board. Therefore, the unit and shutdown batteries have adequate capacities and are capable of supplying the minimum acceptance voltage to the safety-related loads. Based on its review, the

NRC staff finds that the 250-V DC unit and shutdown batteries are adequately sized to support operation at EPU conditions.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the DC onsite power system and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system's functional design. The NRC staff further concludes that the DC onsite power system will continue to meet the requirements of draft GDC-24 and 39 following the implementation of the proposed EPU. The DC system has the capacity and capability to supply power to all safety loads and other required equipment. The NRC staff also finds that Browns Ferry will continue to meet the independence, redundancy, and testability requirements of GDC-17 since no changes were made to these requirements for EPU operations. 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 non-essential 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 (AAC) sources. The NRC staff's review focused on the impact of the proposed EPU on the plant's ability to cope with and recover from an SBO event for the period of time established in the plant's licensing basis. The NRC's acceptance criteria for SBO are based on 10 CFR 50.63. Specific review criteria are contained in SRP Sections 8.1 and Appendix B to SRP Section 8.2; and other guidance provided in Matrix 3 of RS-001.

Technical Evaluation

In Browns Ferry UFSAR Section 8.10, "Station Blackout," the licensee stated that the Browns Ferry SBO is postulated as the failure of the two EDGs in one unit that normally feed a respective unit's 480-V AC shutdown boards concurrent with the loss of all offsite power. The coping strategy is to shut down the blacked-out unit with equipment powered from the 250-V DC battery system. The AAC power from the EDGs in the non-blacked-out units will be made available to power additional required heating ventilation and air conditioning (HVAC) and common loads. The AAC power will be available within 1 hour through existing cross-ties. The SBO coping duration for Browns Ferry is 4 hours.

The licensee re-evaluated the Browns Ferry SBO requirements using the guidelines of Nuclear Management and Resources Council (NUMARC) 87-00, "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors" (Reference 155), and RG 1.155, "Station Blackout" (Reference 156). The license provided the evaluation for the following major characteristics for an SBO event: Condensate inventory for decay heat removal, Class 1E battery capacity, compressed gas capacity, effects of loss of ventilation, and containment isolation. The Browns Ferry SBO coping duration remains 4 hours for EPU operation. The staff's evaluation for the Browns Ferry SBO at EPU conditions is discussed in the following paragraphs.

Condensate Inventory for Decay Heat Removal

In the PUSAR Section 2.3.5, the licensee stated that approximately 114,000 gallons of the condensate storage tank (CST) water is required for RCIC and HPCI use at EPU conditions to remove decay heat, depressurize the reactor, and maintain reactor vessel level above the top of active fuel during the 4-hour SBO coping period. The current CST inventory reserve is about 135,000 gallons. Since the required CST volume of 114,000 gallons is within the current CST inventory reserve of 135,000 gallons, the staff finds that the CST inventory is adequate for SBO mitigation during the coping period at EPU conditions.

Class 1E Battery Capacity

The 250-V DC unit batteries supply the required SBO loads for the coping duration of four hours. SBO loads include loads associated with the HPCI and RCIC systems. For EPU operation, the licensee stated that the EPU containment analysis analytical model (SHEX) model predicted one short HPCI loading cycle for SBO mitigation, while the existing battery capacity analysis for SBO mitigation assumed various HPCI loads operation for longer periods. In addition, the SHEX model predicted a number of RCIC cycles in the EPU mitigation sequence less than RCIC initiations assumed in the battery capacity analysis.

In response to an NRC staff RAI, in the June 17, 2016 (Reference 22), letter, the licensee provided the summary of the battery capacity analysis for the 4-hour SBO mitigation at EPU conditions. The summary included the assumptions, the methodology, and the results of the analysis. The analysis assumed that cycling loads are superimposed (start at the beginning of each defined time period and run continuously during the entire period to be conservative) on each section of the battery duty cycle. The methodology includes the worst case sequence of events when both HPCI and RCIC systems operate during the SBO. The sequence shows that the HPCI injects once and then is cycled again to be placed in test mode for decay heat removal, and the RCIC cycles seven times. The results provide the worst case minimum voltage at the battery terminals, battery boards, and reactor MOVs boards. The staff reviewed the analysis and finds that the unit batteries are capable of supplying power to the DC SBO loads (battery boards and reactor MOV boards) since the calculated minimum voltages at the battery terminals and the boards met the minimum acceptance criterion of 210 V. Therefore, the NRC staff finds that the unit batteries have adequate capacity to support SBO mitigation for the coping duration of four hours at EPU conditions.

Compressed Gas Capacity

In the PUSAR Section 2.3.5, the licensee stated that the EPU SBO evaluation showed that the compressed gas capacity exists for the Browns Ferry air operated MSRVs automatic and manual operation which is required for decay heat removal during the 4-hour SBO event at EPU conditions. Based on simulations for the EPU SBO using the NRC-accepted SHEX computer code, 74 total MSRV cycles are required as compared to the compressed gas inventory, which is capable of thousands of cycles. The licensee further stated that sufficient capacity remains to perform emergency reactor pressure vessel depressurization, if required. Since the maximum number of MSRV required cycles is well within the capability of the compressed gas inventory, the NRC staff finds that Browns Ferry has adequate compressed air capacity to support reactor pressure vessel depressurization during an SBO event at EPU conditions.

Effects of Loss of Ventilation

The licensee provided a summary of the evaluation performed for the effect of loss of ventilation in the following dominant areas containing electrical equipment necessary to cope with an SBO: drywell, control building rooms, reactor building shutdown board rooms/electrical board rooms, RCIC room, HPCI room, main steam tunnel, reactor building general floor area, and torus room.

For the drywell, the peak drywell temperatures during an SBO at both CLTP and EPU conditions is 276 °F. In Section 2.3.1, "Environmental Qualification of Electrical Equipment," of this SE, the staff finds that the components' maximum qualification testing temperatures inside the drywell bound the EPU DBA drywell peak temperature of 337 °F. Since the maximum drywell EPU SBO temperature (276 °F) is less than the maximum drywell EPU DBA temperature (337 °F), which is bounded by the component maximum qualification temperatures, the staff finds that the operability of electrical equipment inside the drywell is maintained during the 4-hour SBO at EPU conditions.

For the control building rooms and reactor building shutdown board and electrical boards rooms, the licensee stated in its letter dated June 17, 2016, that HVAC remains available in these areas during an SBO event, and as such, an analysis for loss of ventilation is not required per NUMARC 87-00, Section 2.7.1, Effects of Loss of Ventilation – Assumptions. NUMARC 87-00 (Reference 155), Section 2.7.1 states: "For multi-unit control room complexes (i.e., area(s) containing instrument indications and associated logic cabinets which the control room operator relies upon to cope with a station blackout) where a portion of the HVAC is powered from the non-blacked-out unit, no significant temperature rise above normal operating conditions is expected. For this situation, the effects of loss of ventilation need not be considered further [to assure operability for a 4-hour station blackout]." Based on this recommendation of NUMARC 87-00, the staff finds that the operability of equipment located in the above-mentioned areas will be not be impacted by a loss of ventilation during the 4-hour SBO since the HVAC in those areas will be powered from the non-blackout units during the SBO.

For the RCIC room, HPCI room, main steam tunnel, reactor building general floor area, and torus room, the licensee in its letter dated June 17, 2016, provided the maximum temperatures expected in these locations during the SBO event at EPU conditions. All the maximum temperatures in the above-mentioned areas remain within the design and qualification temperatures of the SBO equipment. Therefore, the NRC staff finds that the licensee has adequately addressed the effects of loss of ventilation during the SBO event corresponding to EPU conditions.

Containment isolation

In the PUSAR Section 2.3.6, the licensee stated that the containment isolation capability is not adversely affected by the SBO event for EPU as the SBO environment conditions do not change significantly after the EPU, and containment isolation is not adversely affected by the SBO for EPU conditions. The NRC staff finds that the licensee's assessment for containment isolation capability is reasonable and, therefore, is acceptable.

EDG reliability

In its letter dated June 17, 2016 (Reference 22), in response to an NRC staff RAI, the licensee stated that the EDGs' reliability program is not impacted by the EPU, and no plant modifications are required for the EPU.

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 an SBO event 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 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 protection system (RPS), 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 the design of protection and control systems are based on Title 10 of the *Code of Federal Regulations* (10 CFR), 50.55a(a)(1), 10 CFR 50.55a(h), final GDC-19, and draft GDC-1, 12, 13, 14, 15, 19, 20, 22, 23, 25, 26, 40, and 42. Specific review criteria are contained in NUREG-0800 (SRP), Sections 7.0, 7.2, 7.3, 7.4, 7.7, and 7.8, issued March 2007.

Technical Evaluation

The licensee references the GE-Hitachi Nuclear Energy Americas LLC (GEH) licensing topical report NEDC-33004P-A (commonly known as CLTR), "Constant Pressure Power Uprate," which the NRC-approved in a letter dated March 31, 2003 (Reference 48). The constant pressure power uprate (CPPU) approach maintains a plant's current maximum operating reactor pressure. The constant pressure constraint, along with other required limitations and restrictions discussed in the CLTR, allows a simplified approach to power uprate analyses and evaluations.

The licensee in the LAR, Attachments 6 (proprietary) and 7 (Reference 47), as updated by Enclosures 1 (proprietary) and 2 of October 28, 2016 letter (Reference 37), Section 2.4.1.3 states that the setpoint calculations in support of the average power range monitor (APRM) and rod block monitor (RBM) setpoint functions were based on NEDC-31336P-A, "General Electric Instrument Setpoint Methodology," which was approved by the staff by letter dated November 6, 1995 (Reference 157). For all other TS instrument setpoint functions, TVA uses the existing TVA setpoint methodology, "Tennessee Valley Authority Branch Technical Instruction Setpoint Calculations," BTI-EEB-TI-28.

2.4.1.1 Suitability of Existing Instruments and Settings

For the proposed power uprate, the licensee evaluated the existing instruments of the affected nuclear steam supply systems and balance-of-plant systems to determine their suitability for the revised operating range of the affected process parameters.

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

Instrument/Parameter	Description
RPS - Allowable Value (AV) for APRM Flow Biased Simulated Thermal Power – High (TS Table 3.3.1.1-1, APRM Function 2.b)	Current Table 3.3.1.1-1, Function 2.b, "APRM Flow Biased Simulated Thermal Power – High provides an allowable value of ≤ 120 % RTP. Although the APRM – Flow Biased Simulated Thermal Power – High setpoint is changed, the clamped high value remains the same in terms of % RTP. Function 2.b will perform the same under EPU as CLTP to the high neutron flux trip setpoint clamp setting. The APRM - Flow Biased Simulated Thermal Power - High trip level is varied as a function of recirculation drive flow (i.e., at lower core flows, the setpoint is reduced proportional to the reduction in power experienced as core flow is reduced with a fixed control rod pattern) but is clamped at an upper limit that is slightly lower than or equal to the fixed APRM Neutron Flux – High function allowable value. Because of the increase in RTP from CLTP to EPU, the clamped high value setting remains the same in terms of RTP % consistent with the assumptions used in the revised safety analyses.
RPS - Allowable Value for APRM Neutron Flux – High (TS Table 3.3.1.1-1, APRM Function 2.c)	Current Table 3.3.1.1-1, Function 2.c, APRM Neutron Flux – High provides an allowable value of ≤ 120% RTP. The clamped high value remains the same in terms of % RTP. Function 2.c will perform the same under EPU as CLTP to the high neutron flux trip setpoint clamp setting.

Instrument/Parameter	Description
Control Rod Block Instrumentation Table 3.3.2.1-1 Function 2, "Rod Worth Minimizer (RWM)," (Surveillance Requirement (SR) 3.3.2.1.2, SR 3.3.2.1.3, SR 3.3.2.1.5, and Table 3.3.2.1-1 note (c))	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 3.3.2.1.5, and Table 3.3.2.1-1 note (c) are required to be Applicable, in part, in MODES 1 and 2 with THERMAL POWER ≤10% RTP. The 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 range in terms of absolute power when RWM requirements apply and will continue to prevent exceeding the fuel damage limit during a control rod drop accident.
Control Rod Block Instrumentation (TS 3.3.2.1.8 and Table 3.3.2.1-1 notes (a), (b), (f), (g) and (h))	The analytical limit (AL) associated with the analytical value power levels for the various ranges of RBM operability are unchanged in terms of percent power for EPU, thus no setpoint change is required. This is consistent with the CLTR.

In addition, several balance of plant (BOP) monitoring and control instruments will be recalibrated and rescaled to accommodate the EPU. In particular, the pressure control system, turbine steam bypass system, feedwater control system and leak detection system that are part of the BOP will be modified to accommodate the EPU. However, these systems are non-safety related and thus they are generically dispositioned by the CPPU CLTR.

Based upon its review of the data provided by the licensee, the NRC staff concludes that the instruments identified above – with the noted modifications – are capable of serving their intended functions at EPU conditions. The licensee will make these noted modifications to accommodate the revised process parameters affected by the EPU. A discussion of the instrumentation and parameter changes that modify the setpoint or values of TS for Browns Ferry is provided in Section 3.3 of this safety evaluation.

2.4.1.2 Instrument Setpoint Methodology

EPU operating conditions require setpoint changes or rescaling 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.

TVA evaluated changes in process variables and their effects on instrument performance and setpoints for EPU operation to determine any related changes. For those instruments that will not be changed for the EPU, the CLTR outlines a simplified process to determine instrument AVs and setpoints for most instruments. TVA has elected not to use the simplified methodology. Where the power increase results in new instruments being employed, a setpoint calculation was performed and TS and/or Technical Requirements Manual changes are implemented, as appropriate. In this case, TVA used the single-sided GE Nuclear Energy, "General Electric Instrument Setpoint Methodology," NEDC-31336P-A (Reference 157), to determine the new setpoint value for the APRM and RBM setpoint functions, and the existing TVA methodology, "Tennessee Valley Authority Branch Technical Instruction Setpoint Calculations," BTI-EEB-TI-28, for all other setpoint functions to the Technical Specification

instrument setpoints. The TVA methodology was approved by the NRC in its letter dated September 14, 2006 (Reference 158).

The licensee in the PUSAR (Enclosures 1 and 2 of October 28, 2016, letter), Section 2.4.1 summarizes the results of safety evaluations that were performed to justify uprating the licensed thermal power at Browns Ferry. In addition, the licensee in Section 2.4 of the PUSAR describes the setpoint calculation methodology, safety limit-related limiting safety system settings determinations, and instrument setpoint controls. In response to an NRC staff RAI, TVA, in its letter dated April 5, 2016 (Reference 12), provided a summary of the calculation used to calculate the AVs for the APRM flow biased simulated thermal power – high scram based on the revised ALs. A review of this summary calculation is included below:

2.4.1.3 APRM Simulated Thermal Power (STP) – High

Function 2.b of Browns Ferry TS Table 3.3.1.1-1 is referred to as the APRM Flow Biased STP - High. The CLTR states that the effect on the APRM flow biased scram due to EPU is increased reactor power level. The APRM STP – High function provides protection against transients where thermal power increases slowly and protects the fuel cladding integrity by ensuring the minimum critical power ratio safety limit is not exceeded. The licensee notes in the LAR Enclosure, Section 3.1.9.f that no credit is taken in any safety analysis for the flow referenced setpoints. The AV is being revised in accordance with the CLTR.

In Supplement 10 to the LAR (Reference 12), the licensee provided a summary of the calculation for the "APRM Flow Biased STP - High Scram" allowable values. The calculation is based on the GEH Instrument Setpoint Methodology, NEDC-31336P-A, which includes the use of bias and random uncertainties. These uncertainties include channel calibration accuracy, channel instrument drift, primary element accuracy, and process measurement accuracy. In accordance with NEDC-31336P-A, these random uncertainties were combined using the square root of the sum of the squares methodology and the bias terms were summed algebraically.

The current APRM STP – High AVs are:

Two-Loop Operation: $\leq 0.66W + 66\%$ RTP
Single-Loop Operation: $0.66 (W - \Delta W) + 66\%$ RTP

The new APRM STP - High AVs will be revised prior to EPU implementation to:

Two-Loop Operation: $\leq 0.55W + 65.5\%$ RTP
Single-Loop Operation: $0.55 (W - \Delta W) + 65.5\%$ RTP

In the above equations, "W" is the total recirculation drive flow in percent of rated flow. "ΔW" is the difference between the dual-loop operation and single-loop operation drive flow at the same core flow. The current value of ΔW is 10 percent and is not changed.

Based on the information presented, the staff found the uncertainties terms and setpoint calculation acceptable to meet 10 CFR 50.36(c)(1).

2.4.1.4 Main Steam line (MSL) High Flow Isolation

The MSL high flow isolation setpoint is used to initiate the isolation of the Group 1 primary containment isolation valves. The only safety analysis event that credits this trip is the main steam line break accident. For this accident, there are diverse trips from high area temperature and high area differential temperatures in the main steam tunnel. For Browns Ferry, the licensee in PUSAR Section 2.4.1.3.1 states there is sufficient margin to choke flow, so the AL and AV for EPU conditions is unchanged from the current percent of rated steam flow in each MSL. No new instrumentation is required, because the existing instrumentation has the required upper range limit and calibration span for the instrument loops to accommodate the new setpoint. Although the AL and AV are unchanged in terms of percent of rated steam flow, TVA calculated a new setpoint and AV using the TVA methodology for the differential pressure at the allowable steam flow. The AV for TS Table 3.3.6.1-1 Function 1.c for MSL Flow – High is in terms of percent of rated steam flow and is therefore not affected by the EPU. Based on the information presented, the NRC staff found the setpoint calculation acceptable to meet 10 CFR 50.36(c)(1).

2.4.1.5 Turbine First-Stage Pressure Scram and Recirculation Pump Trip Bypass

The turbine first-stage pressure (TFSP) setpoint is used to reduce scrams and recirculation pump trips (RPTs) 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.

The CLTR states that the effect on the TFSP scram bypass permissive due to the EPU is increased reactor power level and potential change to the TFSP. The EPU results in an increased power level and the high pressure turbine modifications result in a change to the relationship of TFSP to reactor power level. Because of this, the current AL of 30 percent RTP is being revised to 26 percent RTP. This change will maintain the AL for EPU at an equivalent absolute steam flow for the current setpoint, and is consistent with Section F.4.2.3 of the NRC-approved ELTR1 (Reference 49).

[[

]]. TVA calculated, PUSAR Section 2.4.1.3.2, a revised setpoint and AV, in terms of psig, using the TVA methodology discussed above. To assure that the new value is appropriate, the licensee stated in the LAR that it will perform an EPU plant ascension startup test or normal plant surveillance to validate that the actual plant interlock is cleared consistent with the safety analysis.

Based on the information presented, the staff found the licensee's proposed method for calculating and validating the revised setpoint and AL to be acceptable to meet 10 CFR 50.36(c)(1).

Conclusion

The NRC staff has reviewed the licensee's application related to the effects of the proposed EPU on the functional design of the RPS, 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 GDC-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 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 system. NEDC-33004P-A, Revision 4, "Constant Pressure Power Uprate," Class III, July 2003 (CLTR) (Reference 48) states that an EPU results in no change in the inventory contained in moderate energy lines. The flow rates and/or the system inventories of analyzed moderate energy piping systems do not increase for an EPU. System design limits (design pressure) used as input to the moderate-energy line break (MELB) flooding analyses are not changed by an EPU.

The licensee, in Section 2.5 of PUSAR (Reference 37), provided an evaluation of the 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 feedwater system for changes in flood mitigation capacity because of the 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 the existing hotwell inventory, the flood levels in the reactor building from a feedwater 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.

Sources of flooding and protection measures in the circulating water system (CWS) are not affected by the EPU. The CWS is located in the turbine building, which is sealed from the reactor building to an elevation of 572.5 feet, and the time for operator action remains valid, as the EPU does not increase the design pressure for the CWS.

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 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 the EPU. Therefore, operation at the uprated power does not affect the ability of the plant to cope with the effects of flooding from MELBs.

Because the current flooding analysis bounds postulated flooding at the uprated power, the licensee will still meet the criteria in draft GDC-2. Therefore, there is 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 internal 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, without loss of the capability to protect the public, the additional forces that might be imposed by natural phenomena such as earthquakes, tornadoes, flooding conditions, winds, ice, and other local site effects. Specific review criteria are contained in SRP Section 9.3.3.

Technical Evaluation

The NRC approved the GE Nuclear Energy Licensing Topical Report, NEDC-33004P-A (CLTR) (Reference 44) as an acceptable method for evaluating the effects of Constant Pressure Power Uprates (CPPUs). Section 8.1 of the CLTR addresses the effect of CPPU on 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 Browns Ferry equipment and floor drains inside and outside of containment has sufficient capacity to handle the added liquid increases expected during operation at the uprated power level.

Because the current EFDS is capable of handling the slight increase in liquid waste inventory, the licensee does not plan to make structural modifications to the EFDS. The EFDS should continue to meet the criteria set forth in draft GDC-2. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the EFDS.

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 (MC) 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. The evaluation of the CWS at EPU power indicates

sufficient system capacity to ensure that the plant maintains adequate condenser backpressure. Condenser backpressure limitations may require load reductions at the upper range of the anticipated circulating water inlet temperatures. 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. The effect of EPU on the flooding analyses is addressed in SE Section 2.5.1.1.1. 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 and determined that the licensee has adequately evaluated the impact of the EPU on the CWS. The NRC staff concludes that based on evaluation of the original design capacity of the CWS and the cooling tower system over the actual range of circulating water inlet temperatures, the circulating water system and heat sink are adequate for EPU operation and implementation of the proposed EPU would not result in the failure of safety-related SSCs following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the CWS.

2.5.1.2 Missile Protection

2.5.1.2.1 Internally Generated Missile

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

The NRC-approved the GE Nuclear Energy Licensing Topical Report (TR), NEDC-33004P-A, Revision 4, "Constant Pressure Power Uprate," (also referred to as CLTR) (Reference 48) as an acceptable method for evaluating the effects of CPPUs.

Section 7.1 of the CLTR states that the increase in steam flow can change the previous missile avoidance and protection analysis. The only safety related evaluation is the plant specific turbine generator missile avoidance and protection analysis.

As defined by RG 1.115, "Protection Against Turbine Missiles" (Reference 159), the designs of the turbines at Browns Ferry for all three units are favorably oriented, which provides missile

protection. In the event of a turbine failure, missiles are ejected away from the safety-related SSCs, and important-to-safety non-safety related SSCs, by orienting the main and reactor feed pump turbines perpendicular to the control bay, reactor building and other structures containing safety-related and important-to-safety systems and components.

The licensee has replaced the BFN Unit 1 low pressure turbine rotors with monoblock integral rotors. A missile generation study is not required because the new rotors are not susceptible to low speed rotor failure. For BFN Units 2 and 3, the licensee performed calculations for turbine missile damage probability using an NRC-approved methodology (Reference 159) and determined that the worst case probability based on inspection frequency and turbine valve testing is 3.3×10^{-8} per year which is below the acceptance criteria of 1×10^{-7} per year. The probability of a turbine missile event as a result of an overspeed is acceptable for the EPU.

The missile analyses for auxiliary systems located in the reactor building for the normally operating systems or the standby emergency core cooling system (ECCS) remain valid because there is no increase in the operating pressure. This results in no change in the potential for generation of missiles. However, pressure does increase in the condensate and feedwater systems (CFSs) but the areas of increased pressure are not in the vicinity of SSCs important to safety as defined by RG 1.115, Appendix A.

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 the plant's current design.

The licensee will continue to meet the requirements of draft GDC-40, which provides reasonable assurance that SSCs important to safety will continue to be protected from internally generated missiles. Therefore, the NRC staff finds the proposed EPU acceptable with regard to 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 (Reference 44) addresses the effects of power uprates on the turbine-generator. 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 turbine generator and that modifications are usually required to support the power uprate. The turbine generator 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 turbine and generator design allows a maximum flow-passing capability and generator output in excess of current rated. The licensee refers to, in PUSAR (Reference 37) Section 2.5.1, 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 units.

The original Browns Ferry main generators were rewound in anticipation of uprating the power. At CLTP and at a reactor dome pressure of 1,050 psia, the main turbines operate with a current rated throttle steam flow of 14.153 million pound mass per hour (Mlbm/hr) at a throttle pressure of 1,000 psia. At EPU rated thermal power (RTP) and at a reactor dome pressure of 1,050 psia, the main turbines will operate with a rated throttle steam flow of 16.44 Mlbm/hr at a throttle pressure of 983 psia. The main generators are currently rated at 1,330 MVA at a 0.95 power factor for Unit 1 and 1,332 MVA at a 0.93 power factor for Units 2 and 3.

The licensee redesigned the current high pressure turbine for each unit which is not capable of passing the required EPU steam flow rate. The new high pressure turbine has been redesigned with replacement diaphragms, buckets, and a new rotor, for at least the minimum target throttle flow margin, to increase the flow passing capability. Per CLTR Section 7.1, a plant specific turbine generator missile avoidance and protection analysis is not required for the new monoblock rotors. The new high pressure turbine section will include a 5 percent flow margin in order to ensure that it will be capable of passing the rated throttle flow and allow for reactor pressure control. To reduce the probability of low pressure turbine rotor blade failure and ejection, the licensee performed modifications and inspections to the shrunk-on wheels for the low pressure turbine for BFN Units 2 and 3 as part of the EPU. (Unit 1 currently uses monoblock rotors for the low pressure turbines and its high pressure turbine rotors will be replaced with monoblock type before entering EPU operations.)

Appendix A of the CLTR states that although the power uprate slightly increases the energy trapped in the turbine following a load rejection, the turbine overspeed would remain within design limits. The turbine overspeed calculation compares the entrapped steam energy contained within the turbine, which increases slightly for EPU conditions, and the associated piping, after the stop valves trip, and the sensitivity of the rotor train for the potential overspeed capability.

The licensee considered the turbine overspeed scenario where the EHC controls and the control and intercept valves fail to respond to the initial overspeed due to a load rejection event. For this scenario, the unit rapidly accelerates to the overspeed trip setpoint, thereby trip-closing

the main and intermediate stop valves. The operating condition analyzed was the maximum power, valves wide open case, with low backpressure. This approach accounts for the two basic contributors to peak overspeed due to a load rejection event: 1) the energy due to entrapped (or entrained) steam within the steam path and inlet piping downstream of the main and intermediate steam valves; and 2) what is termed "valve lag overspeed," which takes into account the energy contributed by new steam entering the machine during the response time of the control and trip systems, and during the actual closing time of these valves. The overspeed trip setpoint is established such that the resulting peak speed will not exceed the 120 percent emergency overspeed limit due to overshoot. This ensures that the turbine is protected in an overspeed event. Although the licensee has not installed the turbine and turbine control system design changes for EPU and the specific control setpoints have not been established, the setpoints will be adjusted to ensure that the turbine will not exceed 120 percent of rated speed due to overshoot.

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. As a result the licensee will continue to meet the criteria in draft GDC-40. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the turbine generator.

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 Piping Outside Containment

Steam lines

The licensee documented in Section 2.2.1.1 of PUSAR (Reference 37) the effect of the EPU on HELB M&E release rates for steam lines outside containment. The licensee concluded that the generic CLTR disposition for high-energy line breaks (HELB) in steam lines is applicable and that the EPU has no effect on HELB M&E release rates for steam lines outside containment.

Liquid Lines

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 evaluated the pipe break criteria based on the requirements of Appendix M of the Updated Final Safety Analysis Report (UFSAR), which is based on current licensing basis requirements. The licensee evaluated the combinations of stresses to meet the requirement of pipe break criteria. Based on these criteria, the licensee did not identify any new postulated pipe break locations.

PUSAR Section 2.2.1.2 documents the effect of EPU on HELB M&E release rates for steam lines outside containment for the RWCU and feedwater systems.

PUSAR Section 2.2.1.2.1 documents the plant specific HELB evaluation for RWCU line breaks.

PUSAR Section 2.2.1.2.2 documents the plant specific HELB evaluation for feedwater line breaks.

PUSAR Sections 2.2.1.2 and 2.5.1.1 documents the effects of EPU operation on the feedwater line break pipe whip, jet impingement, jet reaction and flooding analyses.

Environmental Conditions

All EQ equipment outside primary containment remains above the flood levels resulting from postulated pipe breaks and therefore is not subject to submergence.

Moderate-Energy Piping Outside Containment

For moderate-energy pipe breaks, operation at EPU conditions does not change the system design limits the licensee used as input to the MELB flooding analyses. Because the EPU does not affect the Browns Ferry MELB mass releases and environmental conditions (pressures and temperatures), there is no adverse impact to post-MELB control room habitability or on access to areas important to safe control of post-accident operations.

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 established by National Fire Protection Association (NFPA) 805, "Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants," is to provide assurance, through a defense-in-depth design, that a fire will not prevent the plant from achieving and maintaining the fuel in a safe and stable condition or significantly increase the risk of radioactive releases to the environment during any operational mode or plant configuration. The NRC staff's review focused on the effects of the increased decay heat on the plant's nuclear safety capability assessment to ensure that SSCs required to meet the nuclear safety performance criteria have sufficient capability and effectiveness to satisfy the fire protection program requirements of NFPA 805.

The NRC's acceptance criteria for the fire protection program are based on: (1) 10 CFR 50.48(a) and 10 CFR 50.48(c), insofar as they require the development of a fire protection program to ensure, among other things, the capability to achieve and maintain fuel in a safe and stable condition in the event of a fire (the discussion of RAI 1 in the Technical Evaluation below provides an explanation of these acceptance criteria); (2) General Design Criterion (GDC)-3 of Appendix A to 10 CFR Part 50, 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 fire-fighting systems be provided and designed to minimize the adverse effects of fires on SSCs important to safety; and (3) GDC-5 of Appendix A to 10 CFR Part 50, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions.

Specific review criteria are contained in SRP Section 9.5.1.2, "Risk-Informed, Performance-Based Fire Protection Program," as supplemented by the guidance provided in Attachment 1 to Matrix 5, "Supplemental Fire Protection Review Criteria," of Section 2.1 of RS-001.

Technical Evaluation

The licensee discussed the impact of the proposed EPU, with respect to the Browns Ferry fire protection program, in Section 2.5.1.4, "Fire Protection," and Section 2.11.1.2.2, "Fire Safe Shutdown (FSS) Events," of the LAR Attachment 6 (see attachment 7 (Reference 47) for non-proprietary version) to the Safety Analysis Report for Browns Ferry, EPU, NEDC-33860P, Revision 0, September 2015. The licensee provided additional information regarding fire protection in a letter dated March 24, 2016 (Reference 9).

As discussed in LAR Attachment 6 (PUSAR), Section 2.5.1.4.1, "Fire Protection Program," the licensee evaluated the fire protection program, fire suppression and detection systems, and reactor and containment system responses to postulated fire events. The licensee's evaluation concluded that the proposed EPU for Browns Ferry will meet all Constant Pressure Power Uprate Licensing Topical Report (CLTR) dispositions after the NFPA 805 fire protection program

has been implemented. Specifically, the licensee determined that the following topics will meet the CLTR dispositions:

- Fire Suppression and Detection Systems
- Operator Response Time
- Peak Cladding Temperature
- Vessel Water Level
- Suppression Pool Temperature

The licensee stated in LAR Attachment 6, 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, fire protection responsibilities of plant personnel, administrative controls associated with the fire protection in the Technical Specifications, the Fire Protection Report, and the Nuclear Quality Assurance Plan.

The licensee also stated that the reactor and containment response to the postulated fire events at EPU conditions are described in LAR Attachment 6, Section 2.5.1.4.2. The results show that for the limiting thermal-hydraulic cases, peak fuel cladding temperature, vessel water level, and suppression pool temperature meet the acceptance criteria and there is sufficient time for the operator to perform the necessary action to meet the NFPA 805 requirements to achieve and maintain the fuel in a safe and stable condition in the event of a fire.

As background, the fire protection program technical information in TVA's September 21, 2015, LAR was based on 10 CFR 50.48(b) and Appendix R compliance. Subsequently, on October 28, 2015 (Reference 160), the NRC issued the NFPA 805 fire protection license amendments for BFN Units 1, 2, and 3 in accordance with the requirements of 10 CFR 50.48(c).

The NRC staff, in an RAI, noted that LAR Attachment 6, Section 2.5.1.4, "Fire Protection," states that "the transition to NFPA 805 is currently under NRC staff review, and TVA anticipates its approval prior to implementation [of] EPU operation. Accordingly, the fire protection analysis described in this section is based on the NFPA 805 implementation..." The staff requested that the licensee provide a supplement to LAR Attachment 6 Section 2.5.1.4, "Fire Protection," consistent with the new NFPA 805 licensing basis.

In the letter dated March 24, 2016 (Reference 9), the licensee provided this supplement to the LAR Attachment 6, Section 2.5.1.4 "Fire Protection," and Section 2.11.1.2.2, "Fire Safe Shutdown (FSS) Events." The supplement included a revision that demonstrated that the EPU would be consistent with the 10 CFR 50.48(c) and NFPA 805 licensing basis. The licensee also provided conforming changes related to the fire protection program in LAR Attachment 8, Fuel Uprate Safety Analysis Report (FUSAR), in accordance with 10 CFR 50.48(c) and NFPA 805.

Based on the March 24, 2016 (Reference 9), supplemental letter and supporting information supplied in response to a staff RAI, the licensee adequately addressed the staff's concerns related to the NFPA 805 licensing basis. The licensee identified changes in accordance with 10 CFR 50.48(c) and the NFPA 805 fire protection program for the proposed EPU.

In its RAI, the NRC staff noted that Attachment 1 to Matrix 5 ("Supplemental Fire Protection Review Criteria, Plant Systems"), of RS-001 states that "power uprates typically result in increases in decay heat generation following plant trips. These increases in decay heat usually do not affect the elements of a fire protection program related to procedures and resources necessary for the repair of systems required to achieve and maintain cold shutdown. In addition, an increase in decay heat will usually not result in an increase in the potential for a radiological release resulting from a fire. However, the licensee's LAR should confirm that these elements are not impacted by the EPU." The NRC staff noted that LAR Attachment 6, Section 2.5.1.4.1, "Fire Protection Program," specifically addresses items (1) through (4) above. The staff requested that the licensee provide statements to address item (5) and a statement confirming no increase in the potential for a radiological release resulting from a fire.

In the letter dated March 24, 2016 (Reference 9), the licensee confirmed that the proposed EPU has no impact on the Browns Ferry procedures and resources necessary for the repair of systems required to maintain the fuel in a safe and stable condition. In addition, the licensee also stated that the increase in decay heat has no effect on engineered controls and administrative controls, pre-fire plans, or fire brigade response procedures and training procedures. Therefore, TVA confirmed that at EPU conditions there is no increase in the potential for a radiological release resulting from a fire. The NRC staff finds the licensee's response acceptable because the licensee satisfactorily addressed the fire protection requirements of the RS-001, Revision 0.

In another RAI, the NRC staff noted that LAR Attachment 6, Section 2.5.1.4.1, "Fire Protection Program," states that, "...The higher decay heat associated with EPU results in higher heat input into the suppression pool which, without mitigation, will result in higher suppression pool temperatures. The higher decay heat may also result in lower vessel water levels or higher Peak Cladding Temperatures (PCTs), depending on the plant-specific analysis basis. As a result of these effects, fire suppression and detection systems, operator response time, PCT, and suppression pool temperature need to be addressed..."

The staff requested the licensee to verify that additional heat in the plant environment from the EPU will not (1) impact any required operator manual actions (referred to as recovery actions per the NFPA 805 licensing basis) being performed at their designated time (including, e.g., verifying that under EPU conditions, recovery actions and repairs required to demonstrate the availability of a success path to achieve the nuclear safety performance criteria are feasible and have been evaluated for the additional risk due to their use), or (2) require any new recovery actions due to additional heat in the plant environment to maintain the plant in a safe and stable condition.

In the letter dated March 24, 2016 (Reference 9), the licensee stated that the increases in maximum suppression pool temperature and drywell temperature from CLTP to EPU conditions, after an NFPA 805 fire event, are 2.3 °F and less than 0.5 °F, respectively. The licensee stated that these small temperature increases would have a minimal effect on the local area temperatures where the operator recovery actions are required to take place. Therefore, the licensee concluded that the additional heat load in the plant environment from the EPU will not (1) impact any required operator manual actions being performed at their designated time, or (2) require any new recovery actions, due to additional heat in the plant environment, to maintain the fuel in safe and stable conditions.

Based on its review, the NRC staff concludes that the proposed EPU does not impact current operator recovery actions, nor will new recovery actions be needed. Since there are no changes to recovery actions, the staff considers this response acceptable.

The NRC staff also noted in an RAI that LAR Attachment 6, Section 2.5.1.4.1, "Fire Protection Program," states that, "...Other EPU modifications will be assessed and assured not to adversely affect the ability to achieve and maintain the fuel in a safe and stable condition in the event of a fire..." Further, Section 2.11.1.2.2, "Fire Safe Shutdown (FSS) Events," states that, "Attachment 47 of the EPU LAR provides a listing and discussion of the modifications planned for EPU. The effect of these modifications on the Browns Ferry Fire Protection Program will be evaluated, in accordance with TVA's configuration change process, prior to the EPU implementation. Per the process, these modifications will be evaluated to assure the changes do not affect the approved Fire Protection Program and will not adversely affect the ability to achieve and maintain safe shutdown in accordance with the current Browns Ferry license conditions and procedures..."

The licensee stated that modifications associated with the EPU have not yet been completed. Therefore, the staff requested that the licensee discuss how the results of plant modifications would impact the fire protection program and compliance with the fire protection program licensing basis as per 10 CFR 50.48(c).

In the letters dated March 24 (Reference 9), and August 3, 2016 (Reference 31), the licensee stated that all of the modifications listed in Attachment 47 of the EPU LAR have been reviewed to assess their impact on the fire protection program and compliance with the fire protection program licensing basis as per 10 CFR 50.48(c). The licensee clarified that the hardened wetwell vent modification is the only modification that results in a reduction in plant risk based on the 10 CFR 50.48(c) compliant fire protection program. The licensee concluded that no other modifications listed in Attachment 47 of the EPU LAR would have an adverse impact on the fire protection program or compliance with the licensing basis.

The licensee's response satisfactorily addressed the NRC staff's concerns. The NRC staff finds that these modifications will not affect the plant's NFPA 805 fire protection analysis, and Browns Ferry will continue to be able to achieve and maintain fuel in a safe and stable condition following a fire.

In another RAI, the NRC staff noted that LAR Attachment 6, Section 2.5.1.4.1, "Fire Protection Program," states that, "...Original NFPA 805 analyses were performed at EPU conditions and therefore operator action times cannot be compared to [current licensed thermal power (CLTP)] conditions. To ensure that PCT remains less than the acceptance criterion in the most limiting scenario, one LPCI pump must be manually align[ed] for injection within 20 minutes..." The NRC staff requested the licensee to provide a technical justification for the 20 minute time for the operator to perform the actions to align the low pressure coolant injection (LPCI) pump for injection, to include a discussion of the original time margin without CLTP conditions (i.e., what was assumed for the NFPA 805 analyses), and describe why the 20-minute assumption is deemed adequate.

In the letter dated March 24, 2016 (Reference 9), the licensee stated that, the 20-minute operator action time to align LPCI for injection is unchanged from the 20-minute operator action time assumed in the Browns Ferry Nuclear Plant NFPA 805 LAR. Further, the licensee stated that as part of the NFPA 805 implementation activities, the 20-minute operator action time for

LPCI alignment was re-validated. This revalidation was performed using the fire safe shutdown (FSS) procedures developed as part of the NFPA 805 implementation. This revalidation showed that the maximum time for operators to complete LPCI alignment using the FSS procedures was 15 minutes for all three BFN units which is less than the action time allowed. The licensee's response satisfactorily addressed the NRC staff's concerns. Note that the NFPA 805 Safety Evaluation Report dated October 28, 2015 (Reference 160), Section 3.2.5, "Establishing Recovery Actions," Section 3.4.4, "Additional Risk Presented by Recovery Actions," and Section 3.5.1.6, "Recovery Actions," discuss the acceptability of the recovery actions at a high level (i.e., refers to all recovery actions under NFPA 805 licensing basis and does not explicitly call-out any single operator action (e.g., the operator action to align low pressure coolant injection within 20 minutes)).

The NRC staff noted that LAR Attachment 6, Section 2.5.1.4.2, "Fire Event," states that, "...the results of Case 4, and the evaluations in Section 2.6.5.2, (FUSAR) Section 2.5.1.4, and LAR Attachment 39, demonstrate that the peak fuel cladding temperature, vessel water level, and suppression pool temperature meet the acceptance criteria and the time available for the operators to perform the necessary actions is sufficient. Therefore, EPU has no adverse effect on the ability of the systems and personnel to mitigate the effects of a fire event and satisfies the requirement of achieving and maintaining the fuel in a safe and stable condition in the event of a fire..." The staff requested the licensee to confirm that the above analysis cases at EPU conditions meet the NFPA 805 licensing basis to achieve and maintain the fuel in a safe and stable condition in the event of a fire._In its response dated March 24, 2016, the licensee confirmed that the above analyses at EPU conditions meet the NFPA 805 licensing basis to achieve and maintain the fuel in a safe and stable condition in the event of a fire. The licensee's response satisfactorily addresses the NRC staff's concerns, because the licensee confirmed at EPU conditions that the fuel can be maintained in a safe and stable condition following a fire.

In its last RAI regarding the fire protection system (FPS), the NRC staff noted that some plants credit aspects of the FPS for other than fire protection activities (e.g., utilizing the fire water pumps and water supply as backup cooling or inventory for non-primary reactor systems). If Browns Ferry credits its FPS in this way, the staff requested TVA to identify the specific situations and discuss to what extent the EPU affects these "non-fire-protection" aspects of the plant FPS. Further, the staff requested TVA to discuss, how any non-fire suppression use of fire protection water will impact the ability to meet the FPS design demands.

In the letter dated March 24, 2016 (Reference 9), the licensee stated that Browns Ferry does not credit the FPS for non-fire protection activities in any design basis scenario. However, the Browns Ferry symptom-based emergency operating instructions and severe accident management guidelines provide operator direction for potential use of the FPS for the following non-fire suppression functions during beyond design basis events: (1) reactor pressure vessel injection when preferred water sources are not available; (2) makeup to the spent fuel storage pool(s) when preferred water sources are not available; (3) injection to primary containment for pressure suppression and/or radiological release scrubbing when preferred water sources are not available; and (4) external makeup to the condensate system hotwell in order to use the condensate/feedwater system for reactor pressure vessel makeup. These potential uses are part of the current Browns Ferry configuration, are not affected by the EPU, and are consistent with industry-accepted guidelines.

The NRC staff finds the licensee's response satisfactorily addressed and resolved the NRC staff's concerns and questions because it confirmed that Browns Ferry does not use the FPS for

non-fire protection activities in any design basis scenario. In addition, the licensee clarified that reliance on the FPS for beyond design basis uses is not affected by the EPU.

Conclusion

The NRC staff has reviewed the licensee's fire-related nuclear safety capability assessment and concludes that the licensee has adequately accounted for the effects of the increase in decay heat on the ability of the required systems to achieve and maintain the nuclear safety performance criteria (i.e., its ability to achieve and maintain fuel in a safe and stable condition in the event of a fire). The NRC staff further concludes that the fire protection program will continue to meet the requirements of 10 CFR 50.48(a), 10 CFR 50.48(c), GDC-3 and GDC-5 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 design basis loss-of-coolant accident 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 draft GDC-70, insofar as it requires that the plant design includes a means to control the release of radioactive effluents. Specific review criteria are contained in SRP Section 6.5.3.

Technical Evaluation

The Standby Gas Treatment System (SGTS) maintains secondary containment at a negative pressure and provides 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 offsite dose following a postulated design basis accident (DBA). Section 2.6.6 of PUSAR discusses the flow capacity of the SGTS and its ability to maintain a negative pressure in the secondary containment.

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.

GE performed two bounding analyses for the NRC-approved CLTR to evaluate decay heating in the SGTS for plants that implement the alternative source term (AST) in accordance with RG 1.183 (Reference 161). Comparing the Browns Ferry SGTS design parameters to the CLTR analysis shows that the specific values are bounded. The Browns Ferry SGTS utilizes a low flow cooling system to assure no desorption of radionuclides in the case of increased decay heat. The licensee credits two out of three trains operating during the accident period,

therefore, the values presented are accepted as the maximum heating and iodine loading for one of the two trains. While decay heat from fission products accumulated within the system filters and charcoal adsorbers increases with the increase in thermal power, the low flow cooling 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 analysis for AST application bound the Browns Ferry plant-specific values. Therefore, the Browns Ferry SGTS design and operation under EPU conditions will continue to meet the requirements of draft GDC-70.

Conclusion

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 draft GDC-70. 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: the "hogging" or startup system which initially establishes MC vacuum and the system that 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) draft GDC-70, insofar as it requires that the plant design include means to control the release of radioactive effluents; and (2) draft GDC-17, 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, from anticipated transients, and from accident conditions. Specific review criteria are contained in SRP Section 10.4.2.

Technical Evaluation

The licensee is not modifying the condenser air removal system because operation at the uprated power level 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 MC "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 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 operation. 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 level. As a result, the MCES design bases for Browns Ferry remains unchanged for operation at the uprated power level and the MCES will continue to meet the requirements of draft GDC-17 and 70. 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 required changes to the MCES and concludes that the licensee has adequately evaluated these changes. 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 draft GDC-17 and 70. 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) draft GDC-70, insofar as it requires that the plant design include means to control the release of radioactive effluents; and (2) draft GDC-17, 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 transients, and from accident conditions. Specific review criteria are contained in SRP Section 10.4.3.

Technical Evaluation

The licensee will install larger unloader valves and associated piping to provide additional capability to maintain the seal steam header pressure at approximately 4 psig. Each turbine

sealing system includes a steam seal regulator with the necessary valves to maintain a constant positive pressure in the steam seal supply header and a single steam-packing exhauster condenser equipped with two full-capacity blowers to prevent steam leakage at the turbine shaft seals. The turbine sealing system prevents the leakage of steam into the turbine building and also prevents the leakage of air into the MC. During normal power operations, a pressure regulator valve and two seal steam header unloader valves maintain the seal steam header pressure at approximately 4 psig. To regulate the seal steam header pressure, the unloader valves divert excess seal steam to the MC.

Monitoring of the radwaste building exhaust and the turbine building exhaust is not affected by the EPU; additionally, monitoring of the turbine gland sealing system and the mechanical vacuum pump system are not affected by the EPU.

The licensee has made the modifications in order to ensure the capability of the turbine sealing system to contain activated nitrogen and limit exposure to radiation. Therefore, the turbine gland sealing system will continue to meet draft GDC-17 and 70. The NRC staff finds the proposed EPU acceptable with respect to the turbine gland sealing system.

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 draft GDC-17 and 70. 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

Browns Ferry does not have a Main Steam Isolation Valve (MSIV) leakage control system. This section is not applicable to Browns Ferry.

2.5.3 Component Cooling and Decay Heat Removal

2.5.3.1 Spent Fuel Pool Cooling and Cleanup System

Regulatory Evaluation

The SFP provides wet storage of spent fuel assemblies. The safety function of the SFP 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 SFP 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 safety is not impaired by the sharing; (2) draft GDC-67, insofar that reliable decay heat removal systems are designed to prevent damage to the fuel in storage facilities that could result in radioactivity release to plant operating areas or the public environs; and (3) draft GDC-69, insofar as containment of fuel shall be provided if accidents could lead to

the release of undue amounts of radioactivity to the public environs. 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 (Reference 37), Section 2.5.3.1, the spent fuel cooling section of the fuel pool cooling and cleanup system (FPCCS) consists of two trains of pumps and heat exchangers and two trains of non-safety auxiliary decay heat removal (ADHR). The RHR safety-related system supplemental fuel pool cooling mode may be used to augment the capacity of the FPCCS when the ADHR system is unavailable.

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. EPU will increase the decay heat load 14.29 percent for fuel being offloaded from the reactor.

The licensee stated, in PUSAR Section 2.5.3.1.1, that the decay heat for the EPU was calculated using the formulation and uncertainty factors from American National Standards Institute (ANSI)/American Nuclear Society (ANS)-5.1-1979 with two-sigma uncertainty and correction for miscellaneous actinides and activation products. ANSI/ANS-5.1-1979 was endorsed by the NRC in SRP Section 9.2.5, Revision 3 (Reference 75). 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 result of the evaluation shows that, using the single loss of offsite power (LOOP) of FPCCS and ADHR alone, the licensee can maintain the SFP temperature below the licensing limit of 150 °F.

The SFP normal makeup source is from the Seismic Category II condensate storage system with a capacity of 100 gallons per minute (gpm); it is not affected by the EPU and remains adequate for EPU conditions.

Existing plant instrumentation and procedures provide adequate indications and direction for monitoring and controlling SFP temperature and level during normal batch offloads and the unexpected case of the limiting full core offload. Symptom based operating procedures exist to provide mitigation strategies including placing additional cooling trains or systems in service, stopping fuel movement, and initiating make-up if necessary. The symptom based entry conditions and mitigation strategies for these procedures do not require changes for the EPU.

The licensee evaluated the additional heat load from the EPU using the single LOOP of FPCCS and ADHR alone, for bounding full core offloads added to a bounding SFP heat load from previously offloaded batches. The evaluation concluded that the licensee can maintain the SFP temperature below the licensing limit of 150 °F. The licensee also has plant procedures that limit the rate of heat addition to the fuel pool based on calculated operational heat load limits and available heat removal systems. The licensee has determined that the existing design

capacity of the FPCCS will continue to exceed the SFP heat load that results from EPU operation. Therefore, the NRC staff agrees that the design basis capability of the FPCCS will be maintained following the implementation of the proposed power uprate.

Crud Activity and Corrosion Products

Section 6.3.2 of the CLTR states that crud activity and corrosion products associated with spent fuel may increase slightly during operation at the uprated power level. The amount of crud activity and pool quality are operational considerations and are unrelated to safety.

The licensee evaluated the capability of the FPCCS to maintain water clarity and concluded that water clarity will not be affected by the EPU. Therefore, the NRC staff agrees that the crud activity and corrosion products meet all CLTR dispositions.

Radiation Levels

As discussed in PUSAR, Section 2.5.3.1, 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 14.29 percent, the radiation dose rates increase by 14.29 percent.

The design of SFPs is typically very conservative from the perspective of radiation exposure such that changes in the fuel inventory/bundle surface dose rate of 14.29 percent results in inconsequential changes in operating dose. The licensee has radiation procedures and a radiation monitoring program that would detect any changes in radiation levels and initiate appropriate actions. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the radiation levels around the SFP.

Fuel Racks

As discussed in PUSAR, Section 2.5.3.1, the increase in decay heat from the EPU results in a higher heat load in the fuel pool during long-term storage. The fuel racks are designed for higher temperatures (212 °F) than the licensing limit of 150 °F. The fuel racks at Browns Ferry have a design temperature greater than the licensing limit and meet the limits in Section 6.3.4 of the CLTR. Therefore, the NRC staff finds the fuel racks acceptable for the increase in decay heat from the EPU.

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 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 draft GDC-4, 67, and 69. 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 System

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 equipment cooling water (EECW) and the residual heat removal service water (RHRSW) systems. The NRC staff's review covered the characteristics of the station SWS (i.e., EECW and RHRSW 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; 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 9.2.1, as supplemented by GL 89-13 "Service Water System Problems Affecting Safety-Related Equipment" (Reference 162), and GL 96-06 "Assurance of Equipment Operability and Containment Integrity during Design-Basis Accident Conditions" (Reference 163).

Technical Evaluation

As discussed in PUSAR (Reference 37), Section 2.5.3.2, the EECW system includes pumps, valves, piping and instrumentation to provide cooling water from the ultimate heat sink (UHS) to safety-related plant equipment and backup cooling water to nonessential plant equipment. The EECW system is safety-related and is designed to operate during design basis events. The EECW System provides backup cooling flow to the raw cooling water (RCW) System. The EECW supply valves to the RCW System automatically isolate on low EECW header pressure to guarantee adequate flow to the essential components.

The non-safety-related RCW system provides screened and chemically treated once through cooling water to various non-safety-related plant systems, components, and space coolers. The RCW system may also be operated during loss of power conditions only when standby diesel generated power reserve margin is available. The RCW system includes pumps, valves, piping and instrumentation that provide cooling water to various non-safety-related systems and components, including the turbine-associated equipment heat exchangers and reactor building closed cooling water (RBCCW) heat exchangers.

The non-safety-related RSW system supplies river water for yard-watering, cooling for plant equipment which the RCW system may not conveniently serve, and functions as a keep-fill system for the raw water FPS.

The RHRSW system pumps and associated piping and valves are safety-related and provide cooling water from the UHS to the RHR heat exchangers during normal shutdown, flood conditions, and during post-accident conditions 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 safety-related SWSs during and immediately following the most limiting design basis event, the LOCA, is not significantly affected by reactor power. The licensee has determined that the suppression pool temperature will increase from 172.1 °F to 179.0 °F during DBA-LOCA conditions as a result of RHRSW heat loads. For normal shutdown, the maximum RHRSW heat loads will not increase, because the initiating pressure and temperature are not changing for the EPU.

The licensee stated that the design of the safety-related portions of the RHRSW and EECW systems provide a reliable supply of cooling water during and following a DBA, design basis flood or LOOP conditions. Services that have increased heat loads with EPU conditions are the RHR heat exchangers, RBCCW heat exchangers, RHR pumps room coolers, and CS pump room coolers. Services where heat loads are not RTP dependent are the emergency diesel generator (EDG) heat exchangers (jacket water, air, and lube oil coolers), standby coolant supply system (emergency RHRSW cross-connect to RHR system to provide reactor core or primary containment cooling if RHR is lost), supplemental cooling to SFP, makeup flow to the SFP, the Unit 3 electric board room air conditioning unit, Unit 3 control bay chillers, Unit 3 shutdown board room chillers, control air compressors, and Units 1 and 2 emergency condensing unit.

The NRC staff reviewed the licensee's evaluation of the RHRSW and EECW systems for changes resulting from implementation of the EPU. The staff agreed that the systems will provide the necessary cooling during uprated power operation and are adequate as currently designed.

Water System Performance (Normal Operation)

The proposed EPU results in an increased heat load during normal operation. The increased non-safety related service water system heat loads at Browns Ferry are due primarily to the isolated phase bus duct heat exchangers, certain turbine building pump area coolers and condensate booster pump motor coolers.

Plant modifications to rerate the main generator have been implemented to accommodate the EPU. The main generator stator cooling water and hydrogen cooler heat loads for the uprated main generator are bounded by heat loads for the original generator rating. This is because the uprated generator reactive power output, the primary contributor to stator cooling and hydrogen cooler heat load, is constrained to be less than the reactive power output of the original generator rating. Additionally, the isophase bus duct modifications increased the RCW flow. The RCW system is capable of providing the additional flow. With these increased heat loads, the RCW system discharge temperature increases approximately 0.1 °F at the EPU RTP. The licensee is implementing plant modifications to rerate the main generator and to accommodate operation at the uprated power. The generator rotor modifications will ensure that the service water flow demands for generator stator and hydrogen cooling will be satisfied.

Suppression Pool Cooling (RHR Service Operation)

As discussed in Section 2.5.3.2.3 of the PUSAR (Reference 37), the EPU results in a greater reactor decay heat rate. The containment cooling analysis in Section 2.6.5 of the PUSAR 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 RHRSW. The EPU post-accident containment system response results in an increase in maximum suppression pool temperature from 172.1 °F to 179 °F. A total heat load of 74.2 million British thermal unit (BTU)/hour (hr)/in-service RHR heat exchanger is rejected to the RHRSW as calculated in the containment cooling analysis. The maximum fluid outlet temperature for the RHR heat exchangers during suppression pool cooling will increase to 133.4 °F which remains below the 150 °F design temperature for the RHRSW discharge piping. 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 RHRSW system. The NRC staff finds that the licensee can maintain suppression pool temperature within acceptable limits in the post-accident condition at the uprated power level based on the existing capability of the RHRSW system.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the effects of the proposed EPU on the station EECW and RHRSW 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 station EECW and RHRSW 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 station EECW and RHRSW systems will continue to meet the requirements of draft GDC-4, 40, and 42. Based on the above, the NRC staff finds the proposed EPU acceptable with respect to the station EECW and RHRSW 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, and (2) preventing the occurrence of an accident.

These systems include non-safety related auxiliary cooling water systems, the RBCCW system and raw cooling water (RCW) system, 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 (ESF) 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. Section 2.5.3.2 of this SE contains the evaluation of the safety-related water systems, station SWSs.

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 system. The proposed EPU increases the heat loads on the RBCCW system, but due to an overly conservative analysis that was performed for the CLTP, the computed heat load for the EPU is decreased. The flow rates in the RBCCW system do not change due to the EPU. The only component heat load increase at EPU conditions is an estimated 6.5 percent increase in reactor recirculation pump and motor heat load. The remaining heat loads remain the same or decrease due to excessive conservatism in the CLTP heat load analysis.

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 actual increase in heat load at the uprated power level.

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 GDC-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 PUSAR Section 2.5.3.4, the UHS at Browns Ferry is the Wheeler Reservoir/Tennessee River. BFN-25 UFSAR subsection 1.6.1.1.10f "Loss of Normal Heat Sinks (Downstream Dam Failure)," indicates that the UHS will contain a volume of about 69.6 x 10^6 cubic feet of water in the event of a failure of the Wheeler Dam. The UHS provides heat removal capability for safe reactor shutdown in the event of the site related natural phenomena and failures of structures related to the Safety Evaluation of the UHS. The safety function of the UHS is to provide sufficient cooling water to one accident unit and to two units in shutdown for at least 30 days. The EPU will have no impact on the ultimate heat sink as a source of cooling water for EECW and RHRSW systems which dissipate reactor decay heat and essential cooling loads after a normal reactor shutdown or shutdown following an accident.

The UHS is operated so that the present limits are not changed or exceeded as a result of the EPU. The licensee evaluated the UHS for its capability to handle the increased EPU heat load and determined that the UHS can maintain the cooling water supplied within the design basis minimum water level and minimum flow rate. The evaluation demonstrates that the UHS can maintain the temperature of the water supplied within the maximum design basis temperature of 95 °F during all modes of required operation, and can maintain sufficient water inventory for a 30-day period without makeup. In addition, the EPU will have no impact on the normal heat sink temperature limits or design function. Therefore, the NRC staff finds the proposed EPU acceptable 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 GDC-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 nuclear steam supply system 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

The licensee discussed the heat balance for the EPU conditions in Section 1.3 of PUSAR. The heat balance shows the transport of steam to the power conversion equipment, the heat sink, and to steam driven components. Section 2.2.2 addresses flow-induced vibrations (FIVs) and structural loading of the main steam system piping and supports as well as the function and capability of the MSIVs. The licensee, in PUSAR Sections 2.2.2 and 2.2.3, discussed safety relief valve (SRV) dynamic loads. The NRC staff's evaluation focuses on the dynamic loading from water hammer, SRV setpoint tolerance, and FIV effects.

Structural Evaluation of Main Steam Piping

The NRC approved NEDC-33004P-A, Revision 4, "Constant Pressure Power Uprate," Class III, CLTR (Reference 48) as an acceptable method for evaluating the effects of CPPUs. Section 3.4.1 of the CLTR addresses the effect of a CPPU on FIV in the main steam line (MSL). 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 loads, or SRV discharge loads, thus, there is no effect on the analyses for these load cases.

The increase in main steam flow does result in increased forces from the turbine stop-valve (TSV) closure transient. The TSV closure loads bound the MSIV closure loads because the MSIV closure time is significantly longer than the stop-valve closure time. The licensee evaluated the capability of the main steam piping to withstand dynamic loads at EPU conditions. Section 2.2.2 discusses the code allowable limits with respect to the main steam piping system evaluation which includes the increased loading associated with EPU conditions (i.e., temperature, pressure, and flow, including the effects of the main steam flow induced transient loads at EPU conditions).

SRV setpoint tolerance is independent of an EPU. Browns Ferry transient analyses conservatively bound the existing SRV setpoint tolerance allowable limits. The licensee monitors in-service surveillance of SRV setpoint performance test results separately for

compliance with the TSs and IST program. Browns Ferry has an ongoing evaluation program to resolve problems resulting from SRV surveillance testing exceeding the 3 percent tolerance.

As discussed in Section 2.6.6 of this SE, 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, Browns Ferry 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. The analysis and testing will ensure that the EPU will not increase the instances of SRV vibration resulting from acoustic resonance.

Main Steam line Flow Restrictors

Section 3.5 of the CLTR addresses the effect of CPPU on the MSL flow restrictors. The CLTR states that, during operation at uprated power levels 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. The increase in steam flow rate will result in an increased pressure drop. However, 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 restrictors' 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. **[[**

]] Therefore, the NRC staff finds that the licensee's original analysis for the restrictors after a postulated steam line break remains within the calculated differential pressure drop and choke flow limits under EPU conditions.

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 GDC-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). Because Browns Ferry does not have an MSIV leakage control system, the MC system also serves 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 draft GDC-70, 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

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 CWS 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 level 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 a 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 and the turbine trip setpoint during normal operation. As a result, the licensee will not modify the MC for EPU operation. Condenser backpressure limitations may require load reductions due to circulating water inlet temperatures.

The MC storage capacity was also evaluated for hotwell retention time for the decay of short-lived radioisotopes and was found to remain conservative and acceptable for EPU operation. The EPU does not increase the absolute value in lbm/hr of the steam bypassed to the MC during a load rejection event as discussed in Section 2.5.4.2. The condenser backpressure during a steam dump scenario remains below the high alarm and turbine trip setpoints. In addition, the holdup time for the plate-out of fission products leaking through the MSIVs following core damage remains conservative. Therefore, the proposed EPU is acceptable 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 draft GDC-70 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 turbine bypass system (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. 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 of 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 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. Specific review criteria are contained in SRP Section 10.4.4.

Technical Evaluation

The TBS provides a means of accommodating excess steam generated during normal plant maneuvers and transients. The increase in steam flow during operation at the uprated power reduces the relative capacity of the TBS.

The licensee uses the credited bypass capacity of 389,000 lbm/hr (unchanged from CLTP) as an input to the reload analysis process for the evaluation of AOOs that credit the TBS. Each of the nine bypass valves pass a steam flow of 0.389 Mlbm/hr, resulting in a system bypass capacity of 3.5 Mlbm/hr. Operation at the uprated power does not change the bypass capacity in terms of mass flow. At EPU conditions, rated steam flow is 16.44 Mlbm/hr; the system bypass capability in terms of rated steam flow is 21.3 percent. The bypass capacity at Browns Ferry remains adequate for normal operational flexibility at EPU RTP. Therefore, the Browns Ferry steam bypass capacity used in the turbine steam bypass safety analysis is acceptable 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 GDC-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 nuclear steam supply system 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 to 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 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. Specific review criteria are contained in SRP Section 10.4.7.

Technical Evaluation

The CFS provides a reliable supply of feedwater at the temperature, pressure, quality, and flow rate as required by the reactor. The licensee uses the CFS during normal plant operation. The CFS 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 feedwater requirements of the reactor.

Normal Operation

System operating flows at EPU power levels increase approximately 16 percent of rated flow at the CLTP. The CFS modifications assure acceptable performance with the new system operating conditions. A list of modification descriptions can be found in LAR (Reference 1) Attachment 47.

Transient Operation

The licensee evaluated the feedwater system to account for feedwater demand transients. The evaluation showed the feedwater system could provide a minimum of 5 percent margin above the EPU flow. For system operation with all system pumps available, the predicted operating parameters are within the component capabilities.

The licensee evaluated the feedwater system post-feed pump trip capacity to confirm that with the modifications to the feedwater and condensate system configurations, the capability to supply the transient flow requirements is maintained or increased. The results of the transient analysis performed to determine the reactor level response following a single feedwater pump trip, show that the system response is adequate during EPU conditions (see FUSAR (Reference 164) Section 2.8.5.2.3.2).

Condensate Demineralizers

The licensee evaluated the effect of operation at the uprated power level on the condensate demineralizer. The system experiences slightly higher loadings resulting in slightly reduced condensate filter demineralizers run times; however, the reduced run times are acceptable.

Conclusion

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, withstand water hammer, 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 GDC-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 Systems

Regulatory Evaluation

The gaseous waste management systems (GWMSs) involve the gaseous radwaste system, which deals with the management of radioactive gases collected in the offgas system or the waste gas storage and decay tanks. 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 gaseous waste management systems, (2) methods of treatment, (3) expected releases, (4) principal parameters used in calculating the releases of radioactive materials in gaseous effluents, and (5) design features for precluding the possibility of an explosion if the potential for explosive mixtures exists. The NRC's acceptance criteria for GWMSs 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) draft GDC-70, insofar as it requires that the plant design include means to control the release of radioactive effluents; (4) draft GDC-69, insofar as it requires that containment of fuel and waste storage shall be provided if accidents could lead to release of undue amounts of radioactivity to the public environs; 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

Offsite Release Rate

Radiolysis of water 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. The Browns Ferry site-specific CLTP design basis radiolytic gas production rate, 0.070 cfm/ MWt, is [[

]] Because the offgas system design is greater than the projected actual rate of radiolytic gas production, the Browns Ferry offgas system should have ample margin to accommodate the increase in radiolytic gas production associated with the power uprate.

The licensee administratively controlled the condenser offgas system radiological release to remain within existing site release rate limits. Browns Ferry has TS requirements and administrative controls to limit fission gas releases to the environment. These TSs require plant procedures for improving condenser vacuum and for addressing "fuel cladding failure or high activity in Offgas." Operation at the uprated power level does not affect these procedures.

The GWMS design criteria ensure that the licensee 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. 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.

Recombiner Performance

Radiolysis of water (i.e., formation of H_2 and O_2) in the core increases linearly with power, thus increasing the heat load on the offgas recombiner and related components.

The design features for precluding the possibility of an explosion include: (a) dilution to control the concentration of hydrogen and (b) catalytic recombination to remove the combustible gas. The GWMS at Browns Ferry is consistent with GEH design specifications for radiolytic flowrate. [[ ]] which is below the Browns Ferry site specific design value of 0.070 cfm/MWt (130 °F and 1 atmosphere of pressure).

Therefore, the recombiner and condenser, as well as downstream system components, should handle the effects of the increase in thermal power of the EPU. The quantity of radiolytic hydrogen and oxygen determine the GWMS component design requirements, which are expected to increase in proportion to the EPU power increase. The additional radiolytic hydrogen will also increase the catalytic recombiner temperature and offgas condenser heat load.

These increases have been evaluated, and it has been confirmed that sufficient margin remains in the Browns Ferry Offgas System component design to ensure that the system will continue to satisfy the plant licensing basis.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the GWMSs. 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 systems 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 GWMSs will continue to meet their design functions following implementation of the proposed EPU. The NRC staff further concludes that the licensee has demonstrated that the GWMSs will continue to meet the requirements of 10 CFR 20.1302; final GDC-3, draft GDC-69 and 70; 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 GWMSs.

2.5.5.2 Liquid Waste Management Systems

Regulatory Evaluation

The NRC staff's review for Liquid Waste Management Systems (LWMSs) focused on the effects that the proposed EPU may have on previous analyses and considerations related to the LWMSs' 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 LWMSs 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) draft GDC-70, insofar as it requires that the plant design include means to control the release of radioactive effluents; (3) draft GDC-69, insofar as it requires that containment of fuel and waste storage shall be provided if accidents could lead to release of undue amounts of radioactivity to the public environs; 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

Increased power levels and steam flow result in the generation of slightly higher levels of liquid radwaste. The largest sources of liquid waste are from the backwash of condensate and Reactor Water Cleanup (RWCU) filter demineralizers. Other increases in the LWMS load, such as increased leakage due to higher system pressures, are minimal. The effect of the 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 more frequent backwashes.

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 the EPU, the current design and operation of the LWMS should accommodate the effects of the EPU. The existing equipment and procedures that control releases to the

environment will continue to ensure that releases remain within the applicable guideline values of 10 CFR 20.1302 and 10 CFR Part 50, Appendix I.

Coolant Fission and Corrosion Product Levels

During operation at the uprated power level, increased power levels and steam flow result in the generation of slightly higher levels of concentrations of fission and corrosion products in the reactor coolant.

For evaluating the radiological effects of the EPU, the licensee determined reactor coolant fission and corrosion product radioactivity levels using ANSI/ANS-18.1-1984 in its AST submittal. For the evaluation, input parameters that change as a result of EPU conditions include core power, weight of water in the reactor vessel, condensate demineralizer flow rate, and steam flow rate. The evaluation determined that there is adequate margin between the actual operation source term and design basis source term to accommodate the effects of the EPU. Therefore, the current design basis source term remains bounding.

The current design and operation of the LWMS will accommodate the effects of the EPU with no changes. The existing equipment and procedures that control releases to the environment will continue to ensure that releases remain within the applicable guideline values of 10 CFR 20.1302 and10 CFR Part 50, Appendix I. Therefore, the proposed EPU is acceptable with respect to the LWMS.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the LWMSs. 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 LWMSs to control releases of radioactive materials. The NRC staff finds that the LWMSs will continue to meet their design functions following implementation of the proposed EPU. The NRC staff further concludes that the licensee has demonstrated that the LWMSs will continue to meet the requirements of 10 CFR 20.1302; draft GDC-69 and 70; 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 LWMSs.

2.5.5.3 Solid Waste Management Systems

Regulatory Evaluation

The NRC staff's review for the Solid Waste Management Systems (SWMSs) 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) draft GDC-70, insofar as it requires that the plant design include means to control the release of radioactive effluents; (3) draft GDC-18, insofar as it requires that monitoring and alarm instrumentation shall be provided for fuel and waste storage and handling areas for conditions that might contribute to loss of continuity in decay heat removal and to

radiation exposures, (4) draft GDC-17, 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, from anticipated transients, and from accident conditions; 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. The licensee determined that the EPU does not change the types of solid radwaste which are generated, or add a new type of solid radwaste, as there are no new inputs being added to the radwaste system, and the radwaste system will not be modified as part of the EPU. The primary source of solid radwaste is in the form of spent resins. However, the resin is replaced based on pressure drop across the demineralizer and conductivity design criteria prior to exceeding radiological criteria. Therefore, any increase in the primary coolant activity will not significantly increase the activity of the spent resin.

The radiological sources associated with the 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. Accordingly, there will be no changes affecting the SWMS existing equipment and procedures that control waste shipments and releases to the environment. SWMS existing equipment and procedures will continue to ensure that releases remain within the applicable regulatory guidance.

Waste Volumes

During operation at the uprated power, increased power levels and steam flow result in the generation of slightly higher levels of liquid and solid radwaste. The effect of the EPU on the SWMS is primarily a result of the increased load on condensate filter/demineralizers which the licensee determined to be up to a 15 percent increase in solid radwaste volume, and there is enough margin between the actual solid radwaste volume and design basis volume to accommodate this increase. The SWMS at Browns Ferry will only use approximately 50 percent of the installed process capacity after EPU implementation.

The EPU does not generate a new type of waste or create a new waste stream. As a result, plant operation at the uprated power will not change the types of radwaste requiring shipment. In addition, because the solid volume does not increase above the current design basis waste volume, the current design and operation procedures that control waste shipments and releases to the environment should continue to ensure that releases remain within the applicable regulatory guidance. Therefore, the proposed EPU is acceptable 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, draft GDC-17, 18, and 70, 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 EDG 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 generator 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

The NRC approved NEDC-33004P-A, Revision 4, "Constant Pressure Power Uprate," Class III, CLTR (Reference 48) as an acceptable method for evaluating the effects of CPPUs. The CLTR states that the power uprate does not significantly affect systems not specifically addressed in the CLTR. The CLTR does not address the emergency diesel engine fuel oil storage and transfer system.

There is no change to EDG loads with EPU operation. 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. During operation at the uprate power, the licensee expects no increase in electrical equipment demand on the EDGs. The current emergency system remains adequate because there's no increase in flow or pressure from any of the AC powered ECCS equipment and the current emergency power system has sufficient capacity to support all required loads to achieve and maintain safe shutdown conditions.

As a result, the EPU does not increase the amount of power required to perform safety-related functions (pump and valve loads), and the current emergency power system remains adequate. Therefore, the proposed EPU is acceptable with respect to the EDG fuel oil storage and transfer system.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the amount of required fuel oil for the EDGs 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 GDC-4, and 40. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the EDG 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) draft GDC-68 and 69, insofar as they require that systems that contain radioactivity be designed with appropriate containment and with suitable shielding for radiation protection; and (2) draft GDC-66, insofar as it requires that criticality be prevented. Specific review criteria are contained in SRP Section 9.1.4.

Technical Evaluation

The NRC approved NEDC-33004P-A, Revision 4, "Constant Pressure Power Uprate," also known as CLTR (Reference 48), as an acceptable method for evaluating the effects of CPPUs. Section 6.8 of the CLTR states that the power uprate does not significantly affect systems that are not specifically addressed in the CLTR. ELTR1, Section 5.12 and Appendix J, which was also approved by the NRC for use as guidelines for EPUs, supports section 6.8 of the CLTR.

The CLTR does not specifically address the LLHS. Further, the EPU does not significantly affect the LLHS. The LLHS as currently designed and described in Browns Ferry UFSAR Section 10.3, "Spent Fuel Storage," should continue to meet the requirements of the current licensing basis for radioactivity releases and prevention of criticality accidents. Therefore, 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 draft GDC-66, 68, and 69 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 Loss-of-Coolant Accidents (LOCAs); (2) suppression pool dynamic effects during a LOCA or following the actuation of one or more Reactor Coolant System (RCS) safety/relief valves; (3) the consequences of a LOCA occurring within the containment (wetwell); (4) the capability of the containment to withstand the effects of steam bypassing the suppression pool; (5) the suppression pool temperature limit during RCS safety/relief valve operation; and (6) the analytical models used for containment analysis.

The NRC staff'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 Engineered Safety Features (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) draft GDC-17, 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 NUREG-0800 (SRP), Section 6.2.1.1.C.

Technical Evaluation

BFN, Units 1, 2, and 3, are BWR plants of the BWR/4 design with Mark I type pressure suppression containment. As described in Section 5.2.3 of the UFSAR, the primary containment encloses the reactor vessel, the reactor coolant recirculation system, and other branch connections of the reactor primary system. The pressure suppression system consists of a drywell, a pressure suppression chamber (alternatively referred to as the torus or wetwell) which stores a large volume of water, a connecting vent system between the drywell and the pressure suppression chamber, isolation valves, containment cooling systems, equipment for establishing and maintaining a pressure differential between the drywell and pressure suppression chamber, 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-shaped 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 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. 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 Browns Ferry 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 DBLOCA. The long-term analysis is directed primarily at the drywell gas temperature response for equipment environmental qualification and suppression pool temperature response for the ECCS pumps net positive suction head (NPSH) determination 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 (ELTR1) (Reference 49) using GE computer codes LAMB (Reference 165), M3CPT (Reference 166) and Super Hex (SHEX) (Reference 167). The use of the LAMB and M3CPT codes is approved by the NRC for short term containment LOCA analysis (Reference 49) and (Reference 165). Regarding the use of SHEX for the LOCA and abnormal events long-term containment analysis, Section 4.1 of the NRC Safety Evaluation Report (SER) for the NEDC-33004P-A (CLTR) 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 EPUs for Mark I and Mark III containment designs. . .

Short-Term DBLOCA Analysis for Drywell Pressure Response

The short-term analysis is performed to determine the containment peak pressure during a DBLOCA. The analysis covers the blowdown period during which the maximum drywell pressure and differential pressure between drywell and wetwell occur. The licensee performed this analysis, using the NRC-approved analytic methods for EPUs, for the limiting DBLOCA to demonstrate that the EPU does not result in exceeding the containment design limits. The DBLOCA containment analysis which assumed 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. The licensee stated that the short-term containment pressure response for a main steam line break LOCA is bounded by the limiting DBLOCA short term containment pressure response. 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 M&E release analysis computer code.

In Table 2.6-5 of the PUSAR (Reference 37), the licensee provided a comparison of the values of input parameters between the current analysis and the EPU analysis. The following input parameters remain unchanged: (a) [[ ]] as the RSLB critical flow model; (b) break flow area of [[ ]] of the recirculation suction

line Reactor Pressure Vessel (RPV) nozzle); (c) reactor decay heat model according to ANS 5-1971 plus 20-percent uncertainty; (d) reactor thermal power at 2-percent above the EPU 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 humidity; (h) suppression pool level at its maximum TS limit; (i) initial downcomer submergence height; (j) drywell-to-wetwell vent system pressure loss coefficient; (k) time from scram at which main steam isolation valves (MSIVs) start to close; (l) MSIV closure time; (m) time from scram at which feedwater isolation valve start to close; (n) feedwater valve closure time; (o) drywell volume; (p) wetwell gas space volume; and (q) suppression pool volume. The values of the following input parameters are changed: (a) the initial feedwater temperature is changed from 381.7 °F in the current analysis to 394.5 °F in the EPU analysis; the licensee [[ ]]. The revised feedwater temperature of 394.5 °F is based on the reactor heat balance at 100-percent power and 100-percent core flow under EPU conditions; and (b) the initial reactor pressure conservatively increased from 1,053 psia in the current analysis to 1,055 psia in the EPU analysis, the EPU maximum nominal dome pressure being 1,050 psia.

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 in either the EPU or current analysis because the peak drywell pressure occurs before their initiation.

The licensee performed the short-term analysis for three cases, designated as Design Case (D), Bounding Case (B), and Reference Case (R). All of these cases used the same initial drywell and wetwell pressure of 2.6 psig and 1.5 psig respectively (bounding normal operating pressures, but with different initial drywell temperatures. The initial drywell temperatures used are 70 °F for Case D, 130 °F for Case B, and 150 °F for Case R. Cases D and B were also performed at current conditions to provide a comparison for evaluating the effect of operation at EPU conditions. The licensee stated that the Case D initial drywell temperature of 70 °F is below the lowest initial drywell temperature during normal operation and is therefore conservative for demonstrating the maximum containment pressure response at EPU conditions. The purpose of the Case D analysis was to perform a conservative analysis to demonstrate that a DBLOCA initiated under EPU conditions would not challenge the containment design pressure of 56 psig. The licensee developed the Case B initial drywell temperature of 130 °F with a statistical basis to conservatively calculate containment pressure response due to a DBLOCA at the EPU power level. This temperature represents a lower statistical bound of the 5-year historical drywell operating temperature during normal plant operation. The Case R initial drywell temperature of 150 °F represents the TS maximum drywell temperature during normal operation.

Referring to Table 2.6-5 in PUSAR, Note 3 states:

> The larger drywell volume of 171,000 ft^3 [cubic feet] (compared to the minimum DW [drywell] volume of 159,000 ft^3 (see Table 2.6-2a) results in a larger initial drywell non-condensable gas mass and more non-condensable gas transferred to the wetwell during a LOCA. This maximizes the wetwell and drywell pressure and is conservative.

For the short term drywell pressure response, it appears that using the larger drywell volume of 171,000 ft^3 would result in a less limiting pressure response than using the minimum volume of 159,000 ft^3. In SCVB-RAI 2, the licensee was requested to confirm that maximum drywell and

wetwell pressure response mentioned above (using the larger drywell volume of 171,000 ft^3) was obtained by a sensitivity analysis performed using the LAMB and M3CPT computer codes for drywell volumes of 171,000 ft^3 and 159,000 ft^3 using the same assumptions and same remaining input parameters. The licensee in its letter dated June 24, 2016 (Reference 24), in response to the NRC staff request for additional information (RAI), stated that use of the larger initial drywell volume for peak containment pressure response is based on the sensitivity studies from another Mark I containment plant similar to the Browns Ferry design. The licensee's qualitative explanation is as follows:

> A smaller drywell volume would result in a faster initial drywell pressurization rate and higher predicted drywell pressures very early in the event during the period prior to and shortly after vent clearing. However, the short-term drywell pressure peaks later, after most drywell gas is transferred from the drywell. The transfer of drywell gas to the wetwell pressurizes the wetwell and produces a pressure feedback effect on drywell pressure due to the effect of the higher wetwell pressure on vent flow. Therefore, although a higher initial drywell volume will produce a lower initial pressurization rate in the first few seconds of the event, it will produce the maximum predicted peak drywell pressure.

In response to the NRC staff RAI, the licensee performed a Case D [Design Case] sensitivity analysis for the initial drywell volumes of 171,000 ft^3 and 159,000 ft^3. The comparison of drywell pressures for the two cases shown in Figure SCVB-RAI 2-1 of (Reference 24) is consistent with the licensee explanation given above. For the initial drywell volume of 171,000 ft^3, the peak drywell pressure is 50.9 psig, and for the smaller initial drywell volume of 159,000 ft^3, the peak drywell pressure is 50.3 psig.

The licensee, in Table 2.6-1 of the PUSAR, presented the results of the short-term LOCA containment pressure analysis at the EPU and its design limit. The peak drywell pressure results for the three cases at EPU conditions 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 of 56 psig, the NRC staff finds the licensee's short-term drywell pressure response results at EPU conditions acceptable.

UFSAR Section 5.2.5 and the Browns Ferry TSs address the containment leakage testing requirements in accordance with 10 CFR Part 50, Appendix J, Option B. The Type A, B, and C tests that measure the containment integrated leak rate, containment penetration leak rates, and containment isolation valve leak rates, respectively, are performed using the TS value for P_a which is the peak containment pressure during a DBA. From the containment analysis, the peak containment pressure P_a for Unit 1 increases from its current value of 48.5 psig to an EPU value of 49.1 psig, and for Units 2 and 3 the EPU value of P_a is less than the current TS value of 50.6 psig.

Table 2.6.1-1

EPU Short-Term LOCA Containment Pressure Response Initial Conditions and Results

Parameter	Design Case	Bounding Case	Reference Case	Design Limit
Initial drywell pressure, psig	2.6	2.6	2.6	Not applicable
Initial wetwell pressure, psig	1.5	1.5	1.5	Not applicable
Initial drywell temperature, °F	70	130	150	Not applicable
Peak drywell pressure, psig	50.9	49.1	48.5	56

Long-Term LOCA Analysis for Drywell Gas Temperature Response for Equipment Environmental Qualification

The long-term drywell gas temperature response analysis used the SHEX computer code. The licensee analyzed several break sizes in accordance with NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment," Revision 1, dated July 1981 (Reference 151). The most limiting response was determined to be for the small steam line break (SSLB) area of 0.25 ft^2. In Table 2.6-6 of PUSAR, the licensee provided a comparison of the input parameter values between the current and the EPU long-term drywell gas temperature response and long-term suppression pool temperature analyses and stated that the assumed initial conditions maximize the drywell gas temperature response and the suppression pool temperature response described in Section 2.6.5.1 in this SE.

As stated in Table 2.6-6 of PUSAR, the following input parameter values are unchanged in the current and EPU analyses:

- [[ ]] as the SSLB critical flow model;
- Reactor decay heat model according to ANS 5.1-1979 plus 2 sigma uncertainty;
- RTP at 2-percent above the EPU value to include instrument uncertainty effects;
- Initial containment pressure 2.6 psig;
- Initial drywell relative humidity 20-percent;
- Initial wetwell relative humidity 100-percent;
- Initial suppression pool temperature 95 °F;
- Initial wetwell gas space temperature 95 °F;

- Initial downcomer submergence 2.92 ft;
- Downcomer pressure loss coefficient 5.32;
- Time from scram at which MSIV starts to close 0.5 seconds;
- MSIV closure time 3 seconds;
- RHR heat exchanger hot side flow 6,500 gallons per minute (gpm);
- RHR heat exchanger service water flow 4,000 gpm;
- High Pressure Coolant Injection (HPCI) flow 4,500 gpm.

As stated in Table 2.6-6 of PUSAR, the following input parameters values are changed from the current to the EPU analyses:

- [[ ]];
- [[ ]];
- Initial suppression pool volume is 121,500 ft^3 in the current analysis; it is 122,940 ft^3 in the EPU analysis. The licensee provided the following justification for the difference: "EPU value is determined by accounting for the operating DW-to-Wetwell operating differential pressure. The current design analysis value assumed suppression pool volume without DW/WW [drywell/wetwell] pressure control of 1.1 psid [pounds per square inch differential] between the wetwell and drywell in service. The EPU analysis assumed DW/WW pressure control in service. Browns Ferry Technical Specifications require the DW/WW pressure control to be in service";
- Drywell hold up volume is [[ ]] in the current analysis; realistically modeled as 3,823 ft^3 in the EPU analysis;
- [[ ]];
- [[ ]];

- Drywell free volume is 159,000 ft^3 in the current analysis; and 171,000 ft^3 in the EPU analysis. [[

]];

- The wetwell free volume is 129,000 ft^3 in the current analysis; and 135,000 ft^3 in the EPU analysis. The licensee stated that the volume calculated in the current analysis was incorrect;

- The RHR heat exchanger K-value = 223 British thermal unit (BTU)/(second (sec)-°F) for one heat exchanger with hot side flow of 6,500 gallons per minute (gpm) and service water flow of 4,000 gpm in the current analysis, and 265 BTU/sec-°F in the EPU analysis for the same hot side and service water flows. Refer to Section 2.6.5.3 of this SE for the staff's evaluation of the change in K-value.

- The RHR service water temperature is 92 °F in the current analysis; and 95 °F in the EPU analysis which is more conservative;

- The CS flow is 7,100 gpm in the current analysis, it is 7,100 gpm up to 600 seconds from accident initiation, and 6,250 gpm after 600 seconds. The EPU analysis assumes CS flow throttled to 6,250 gpm by the operator at 600 seconds. The EPU analysis values are consistent with the ECCS LOCA analysis for fuel response;

- Regarding thermal conductors, the licensee stated:

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The SSLB LOCA drywell temperature response was performed for HPCI available and HPCI unavailable cases to determine the effect of the availability of high pressure ECCS on the limiting drywell temperature. The analysis results show that the break area of 0.25 ft^2 with an initial drywell temperature of 70 °F resulted in the most limiting drywell temperature of 336.9 °F and the most limiting electrical equipment qualification temperature profile. For the same break, with an initial drywell temperature of 150 °F, the calculated peak drywell gas temperature of 335.2 °F is less limiting. The licensee stated that maximum drywell gas space temperature and the drywell shell temperature occurs early in the event with the assumption that the LOCA signal (high drywell pressure concurrent with low RPV pressure) for this break occurs at 10 minutes into the event and the initiation of drywell spray occurs at 20 minutes into the event. The NRC

staff requested the licensee to explain the basis for this assumption. In its letter dated June 24, 2016 (Reference 24), the licensee stated the assumption is based on sensitivity studies in the development of GEH SC 11-10 (Reference 168). For larger break sizes (break sizes greater than 0.25 ft^2), the sensitivity studies showed that, the RPV will depressurize rapidly (on the order of 2 to 4 minutes) to below the RPV pressure that initiates the LOCA signal. The assumption that the LOCA signal occurs in the accident unit 10 minutes after the accident initiation is conservative because this assumption coupled with an assumed operator action time of ten minutes to shift RHR from core cooling mode to containment cooling mode results in a longer delay for initiating containment spray and a more severe drywell temperature response. For smaller break sizes (break sizes less than 0.25 ft^2), the sensitivity studies showed that, the RPV will depressurize slowly (on the order of 15 minutes to greater than 1 hour) to below the RPV pressure that initiates the LOCA signal. The EPU containment response analyses for these break sizes showed that the depressurization time to low RPV pressure is actually longer than the times in the sensitivity studies. In recognition that a late LOCA signal would occur at low RPV pressure, as a normal action, the operator would inhibit the late LOCA signal by the operation of permanently installed hand switches in the main control room.

The EPU analysis for the limiting break area of 0.25 ft^2 that resulted in the peak drywell temperature shows that RPV depressurizing to below the RPV pressure that generates the LOCA initiation signal occurs at approximately 8 minutes following the event initiation. The credit for operator action to initiate drywell spray is not taken prior to 10 minutes. To conservatively maximize the time delay to drywell spray initiation, the containment response analysis assumes that the LOCA signal (high drywell pressure concurrent with low RPV pressure) occurs at 10 minutes, concurrent with the time that operator action to initiate drywell spray would have been assumed. The analysis assumes that the operators require 10 minutes following the LOCA signal to ultimately shift RHR from core cooling (LPCI mode) to containment cooling mode. This operator action can be completed in significantly less time (i.e., in approximately 5 minutes). Therefore, the assumption that the LOCA signal occurs in the accident unit 10 minutes after the accident initiation in SSLB accident coupled with an assumed operator action time of 10 minutes is conservative for determining the containment response.

The NRC staff accepts the assumption for the LOCA signal occurring 10 minutes after the accident initiation for break sizes greater than 0.10 ft^2 is conservative because coupled with an assumed operator action at ten minutes after LOCA signal, to transfer RHR from LPCI mode to containment cooling mode results in a longer delay for initiating containment spray and therefore a more severe drywell temperature response. For the smallest break size (0.01 ft^2), the EPU containment response analysis assumes that there is no additional ten minute delay for initiating containment spray due to the generation of the LOCA signal occurring at ten minutes following the event initiation because the operator has time to override the LOCA signal. For this break the operating procedure requires the operator to initiate drywell spray before drywell temperature rises to 280 °F, and to initiate wetwell spray before suppression chamber (torus) pressure rises to 12 psig.

Maximum Drywell Shell Temperature Analysis for Structural Design Limit

The licensee used the SHEX code for calculating the maximum drywell wall temperature using the [[

]] The 0.25 ft^2 SSLB resulted in the maximum drywell wall temperature of 280.8 °F occurring at the beginning of the

event, before the initiation of drywell sprays, because the maximum drywell gas temperature occurs during this early period with maximum heat transfer to the shell. The initiation of the sprays reduces the drywell pressure, and drywell gas and shell temperatures. The calculated maximum temperature of 280.8 °F of the drywell shell is bounded by the 281 °F containment structure design temperature limit. Therefore, based on the above and considering the conservative nature of the analysis, the NRC staff considers the analysis acceptable.

Long-Term LOCA Analysis for Wetwell Gas Temperature Response

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 is 174 °F which is less than the wetwell design temperature of 281 °F. The NRC staff considers the mechanistic modelling an acceptable approach, and therefore the peak wetwell gas space temperature of 174 °F is acceptable.

Local Suppression Pool Temperature with Safety/Relief Valve Discharge

NUREG-0783 (Reference 169) 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. All BFN units have T-quenchers to mitigate the SRV loads. The licensee evaluated the peak suppression pool temperature under EPU conditions, in accordance with the NUREG-0783 (Reference 169) 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 of the local suppression pool temperature with SRV discharge under EPU conditions is acceptable.

Drywell to Wetwell Steam Bypass Leakage

As per NUREG-0800 (SRP) Section 6.2.1.1.C, Revision 7, Appendix A, Section B, item 2.c, the acceptance criterion for Mark I containments with regard to steam bypass leakage, is that the measured leakage should not be greater than the leakage that would result from a one-inch diameter opening ($A/\sqrt{K}$ approximately equal to 0.0033 ft^2). The current steam bypass effective area capability, $A/\sqrt{K}$, established from the licensee's analysis, is 0.18 ft^2, which is approximately 54 times greater than the effective area $A/\sqrt{K}$ of 0.0033 ft^2 of a one-inch diameter opening. The licensee stated that the current TS Surveillance Requirement (SR) 3.6.1.1.2 which verifies the drywell-to-wetwell steam bypass leakage acceptance criteria is not affected by the EPU and remains the same as in the current licensing basis. This SR verifies that the drywell-to-wetwell differential pressure does not decrease at a rate > 0.25 inch water gauge per minute over a 10 minute period at an initial differential pressure of 1 psi. In SCVB-RAI 22, the licensee was requested to state the value of $A/\sqrt{K}$ that would be derived from SR 3.6.1.1.2. In response to a staff RAI, the licensee in its letter dated June 24, 2016 (Reference 24), stated $A/\sqrt{K}$ derived from SR 3.6.1.1.2 is approximately equal to 0.0033 ft^2. The NRC staff agrees that the SR 3.6.1.1.2 is not required to be changed for the EPU because it is based on a value of $A/\sqrt{K}$ which has a large margin from $A/\sqrt{K}$ equal to 0.18 ft^2 established from analysis.

Containment Dynamic Loads

The containment design basis includes an 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 170), 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 133). The licensee addressed the Browns Ferry plant-specific dynamic loads using the NRC-approved methods given in NUREG-0661 (Reference 15). The following loads were addressed as discussed below:

- LOCA Loads
- SRV Loads
- LOCA Pressure and Temperature Loads

LOCA Loads

The short-term DB RSLB is the most limiting break for LOCA containment loads under EPU conditions. 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 dynamic loads are: (a) vent thrust loads during vent clearing caused by the discharge of water into the downcomers by drywell pressurization in the short-term, (b) pool swell loads, (c) condensation oscillation (CO) loads, and (d) chugging 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.

For the pool swell loads, the licensee stated that the current load definition results bound the EPU pool swell loads. Therefore, EPU does not impact the current pool swell loads.

For the CO 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, the EPU does not impact the current CO loads.

For the chugging loads, the licensee stated that the EPU short-term containment response conditions are within the conditions used to define these loads. Therefore, the EPU does not impact the current chugging loads.

The licensee's evaluation for chugging loads under EPU conditions does not change from its current evaluation. The following is the current evaluation of the chugging loads:

GE Licensing Topical Report, NEDO-21888 (Reference 133) defines the onset and duration times for chugging based on break size. The chugging phenomena following an intermediate break accident (IBA) and small break accident (SBA) LOCAs 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, lasting 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 (EOPs) require initiation of drywell sprays before the wetwell pressure exceeds 12.0 psig. The EPU containment analysis shows that the wetwell pressure exceeds the drywell spray initiation pressure of 12.0 psig before 600 seconds following initiation of the event. The licensee stated that the drywell sprays will rapidly reduce the drywell pressure and therefore stop chugging. However, as reported in GEH SC 11-10 (Reference 168), for Browns Ferry, when a LOCA signal is initiated on high drywell pressure concurrent with low RPV pressure, drywell spray initiation could be delayed up to 1200 seconds after initiation of an IBA or SBA LOCA. Therefore, the chugging duration could be extended to a maximum of 1200 seconds, which exceeds the duration times identified in NEDO-21888 (Reference 133) for Mark I containments and Browns Ferry Plant Unique Analysis Report (PUAR) (Reference 171). As mentioned in response (Reference 24) to the NRC staff RAI, the licensee stated that the increased chugging duration to 1200 seconds is a result of the issue identified in GEH SC 11-10 concerning a possible delay in initiating drywell spray and is independent of the plant power level. The chugging loads are not affected by the issue identified in GEH SC 11-10.

The current licensing basis evaluated the effect of the chugging duration extension to 1200 seconds by reviewing the fatigue usage factor of components during an IBA/SBA LOCA given in the Browns Ferry PUAR (Reference 171). The fatigue usage factor is defined as the ratio of the number of cycles anticipated during the lifetime of the component to the allowable cycles. The highest fatigue usage factor during a SBA/IBA LOCA is 0.610 for the downcomer/vent header intersection (the sum of the fatigue usage factor due to SRV actuation (0.392) and the fatigue usage factor due to chugging (0.218)). By linear extrapolation, the fatigue usage factor for 1200 seconds duration chugging is 0.218 * (1,200/900) = 0.291. Therefore, the overall fatigue usage factor is increased to 0.291+0.392 = 0.683, which remains below the allowable fatigue usage factor of 1.0. Following the same approach, the fatigue usage factor for the remaining components is also determined to be below 1.0 for the 1200 seconds duration chugging cycles.

The NRC staff agrees that the current evaluation of chugging loads on wetwell components is not affected because the containment response conditions for EPU are within the conditions used to define the chugging loads, and the increase in chugging duration time to 1200 seconds resulting from the possible delay of drywell spray initiation identified in GEH SC-11-10 does not affect the containment components under EPU conditions.

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 affected 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 licensee stated that in the Browns Ferry long-term plant specific analysis for torus integrity, the maximum reflood height (controlled by the SRV discharge line geometry and the SRV discharge line vacuum breaker capacity) was used in the SRV discharge line which is not affected by EPU. The SRV set points also do not change with the EPU. The NRC staff finds it reasonable and acceptable that the SRV loads due to subsequent SRV actuation are not affected by the EPU.

LOCA Pressure and Temperature Loads

The licensee stated that the current Browns Ferry plant-specific LOCA pressure and temperature loads were obtained from the Browns Ferry plant unique load definition (PULD) report generated during the Mark I Long Term Program, as provided in BFN Report CEB-83-34, Revision 2 (Reference 172), Browns Ferry Nuclear Plant Torus Integrity Long-Term Program Plant Unique Analysis report." This report provided LOCA-induced pressure and temperature results from DBLOCA, IBA, and SBA events as an input for the subsequent use in the Browns Ferry Report CEB-83-34, Revision 2 structural analysis. The IBA and SBA events were reevaluated at 102-percent EPU RTP using initial conditions and assumptions consistent with the Reference 21 analysis. The results of the Browns Ferry EPU analysis show that all drywell and wetwell pressure and temperatures at EPU conditions are bounded by the values of GE NEDO-24580, Revision 2 (Reference 171), "Mark I containment Program Plant Unique Load Definition Browns Ferry," with the exception of the peak wetwell and suppression pool temperature for the SBA. Under EPU conditions, the SBA peak wetwell and suppression pool temperature is 146 °F, which exceeds the value in GE NEDO-24580 result of 136 °F. The licensee provided the following reason why the LOCA pressure and temperature loads in GE NEDO-24580 would still be bounding even though the EPU SBA peak wetwell and suppression pool temperature of 146 °F exceeds the GE NEDO-24580 temperature of 136 °F.

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Section 2.2.2, "Pressure-Retaining Components and Component Supports" of this SE provides the evaluation of the wetwell and suppression piping that have the SBA temperature as a structural load combination input. The current LOCA pressure and temperature load analysis bound the analysis under 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 Systems, Structures, and Components (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 heat removal systems, 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 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 M&E 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 will continue to be adequate for limiting the release of radioactivity during normal and accident conditions and the containment and associated systems will continue to meet the requirements of draft GDC-10, 12, 17, 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 M&E 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 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-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 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 any HELB between the RPV and the SSW.

As stated in UFSAR Section 12.2.2.6, the SSW consists of a 24-foot diameter circular cylinder attached to the vessel support pedestal and extending upward approximately 45 feet. This cylinder forms the outer shell of the annulus; the inner shell is formed by the reactor vessel and support skirt. The pedestal forms the base of the annulus with the top open to the drywell. The SSW is a 27 inches thick double walled shell made of ¼-inch welded plate. The concrete is filled between the shell walls for providing shielding capability. Consistent with the current analysis in UFSAR Section 12.2.2.6, the licensee stated that pipes with nominal diameters of 4-inch or smaller are the only RCS lines investigated, because the reactor vessel safe-end welds for their nozzles are located within the annulus. The minimum wall thickness for the various piping systems occurs at the safe-end weld joint to the piping. All other sections from this joint back to the reactor vessel have thicker wall sections and, therefore, have lower stresses. The largest line that has the safe-end weld joint located in the annulus is the 4-inch jet pump instrument line nozzle. Double-ended break flow for all larger lines would be outside the SSW directly into the drywell volume and not into the annulus.

For calculating the differential pressure across the SSW at 102-percent EPU RTP, the licensee made the following assumptions: (a) annulus to drywell vent does not experience critical flow because of low differential pressure; (b) break fluid flashes into a two phase homogeneous mixture with 100-percent water entrainment; (c) mixture saturation pressure is equal to the annulus pressure; (d) the mixture enthalpy is equal to the break fluid enthalpy; (e) drywell pressure remains constant during the short time period; (f) flow through the annulus to drywell vent is frictionless adiabatic, and (g) non-condensable gas initially in the annulus is vented before the peak time of peak annulus-to-drywell differential pressure.

Based on the reactor downcomer conditions, using the Moody slip critical flow model, the licensee calculated the break mass flux for the following cases: (a) 102-percent EPU RTP at rated flow and normal feedwater temperature, (b) 102-percent EPU RTP at rated flow and feedwater temperature reduction, and (c) reactor operating condition with maximum downcomer subcooling, that is, operation at the limiting off-rated condition along the maximum extended load line limit analysis (MELLLA) operating domain upper boundary (minimum recirculation pump speed with feedwater temperature reduction). By using the modified version of Darcy's scaling formula and accounting for the second order effect of compressible flow, the licensee calculated the differential pressure across SSW to be equal to 2.3 psi at 102-percent EPU RTP with normal feedwater temperature, 2.5 psi at 102-percent EPU RTP with reduced feedwater temperature, and 3.6 psi for the maximum downcomer subcooling operating condition (minimum recirculation pump speed with reduced feedwater temperature). A sensitivity analysis for the initial drywell pressures ranging from 14.4 psia to 17.0 psia indicated less than 1-percent variation in the differential pressure across SSW. The licensee's results show a substantial margin between the calculated differential pressures across the SSW and the 19 psi design limit.

The NRC staff finds the licensee's evaluation of the SSW annulus differential pressure developed due to HELB under EPU conditions is acceptable because the licensee used conservative inputs and reasonable assumptions and showed a high margin between the calculated values and the design limit.

The NRC staff requested the licensee to describe the most limiting analysis and results of the jet reaction forces from a double-ended guillotine break of the 26-inch main steam RPV penetration, the double-ended guillotine break of the 28-inch recirculation loop outlet penetration, and the breaks of feedwater line at EPU power level, using conservative inputs (such as fluid density, jet velocity, etc.). In its response dated June 24, 2016 (Reference 24), the licensee stated that the jet reaction forces on the SSW is a product of the pipe area and internal pressure. The pipe area remains unchanged from the values used in the original design analysis. The original analysis used conservative pressures to calculate the jet force. The 26-inch MSLB utilized a bounding steam pressure of 1325 psig and the 28-inch recirculating loop break utilized a bounding reactor recirculation system pressure of 1250 psig. Both of these pressures bound the operating pressures at EPU conditions. Therefore, jet reaction forces on the SSW and its supports at EPU conditions are bounded by the original design. The licensee confirmed that the SSW and its supports remain capable of carrying the jet loads, as the original design analysis bounds the conditions at the EPU.

The NRC finds the licensee's evaluation of SSW annulus pressurization and jet loads from a double-ended guillotine break of the 26-inch main steam RPV penetration and the double-ended guillotine break of the 28-inch recirculation loop outlet penetration acceptable because the original design analysis was based on conditions that bound the EPU conditions.

The UFSAR Section 12.2.2.6 provides the following description of the effect of jet forces resulting from the postulated break in a 4-inch jet pump instrument line nozzle:

> An analysis has also been performed of the effects of jet forces resulting from a double-ended break of the 4-inch line, assuming the jet forces from the break were to impinge directly on the removable plug. The resulting load would be 11 kips, which is less than the capability of the locking bars and hinges, the capability of the shield wall, and the capability of the reactor vessel and its support skirt.

The NRC staff requested the licensee to provide a description of the analysis and results of the effect of the jet impingement forces from a double-ended break of the same 4-inch line under the most limiting thermal-hydraulic reactor conditions while operating under EPU conditions with a justification that the conditions (such as fluid density, jet velocity, etc.) assumed in the analysis are most limiting. The licensee was also requested to state the load carrying capability of the shield door, shield wall, reactor vessel and its support skirt. In its response dated August 3, 2016 (Reference 30), the licensee stated that the calculation that formed the basis for the current UFSAR Section 12.2.2.6 evaluation regarding the effect of the jet impingement loading from the 4-inch jet pump instrument line break could not be located. The licensee instead performed a jet impingement force evaluation for the postulated instantaneous double-ended break of the 4-inch jet pump instrument line nozzle under the following reactor conditions:

(a) 102-percent original licensed thermal power (OLTP), rated core flow (RCF), and normal feedwater temperature (NFWT)

(b) 102-percent current licensed thermal power (CLTP), RCF, and NFWT
(c) 102-percent CLTP, MELLLA, and NFWT
(d) 102-percent EPU, RCF, and NFWT
(e) 102-percent EPU, RCF, and reduced feedwater temperature (RFWT)
(f) 55.4-percent EPU, MELLLA Line, and RFWT. (55.4-percent EPU condition is 102-percent of the power level at the intersection of the MELLLA line and minimum pump speed line)

Table SCVB-RAI 14-1 in the letter dated August 3, 2016 (Reference 30), presents the thermal-hydraulic parameters at the above reactor conditions. For a conservative analysis, the licensee considered the effect of RFWT (reactor conditions (e) and (f)) which increases subcooling in the RPV downcomer region resulting in higher density of jet fluid discharged, and therefore a higher jet impingement force. The calculation of the jet impingement force and the drag load on the shield door is based on the methods in Appendix D and C respectively of ANSI/ANS 58.2-1988, "Design Basis for Protection of Light Water Nuclear Power Plants against the Effects of Postulated Pipe Rupture." The results of the jet impingement forces and the drag load on the shield door at the above reactor conditions are provided in Tables SCVB-RAI 14-2 and SCVB-RAI 14-3 of the letter dated August 3, 2016 (Reference 30). The structural evaluation based on the maximum drag load confirmed that the shield door can withstand the jet impingement load for the double ended break of the 4-inch jet pump instrument line at EPU conditions. The licensee confirmed that the load capabilities of the shield wall, RPV and RPV support skirt bound the loads resulting from the jet forces from the double-ended break of the 4-inch jet pump instrument line under EPU conditions.

The NRC staff finds it acceptable that the licensee used conservative thermal-hydraulic reactor conditions for analyzing the jet impingement loads from a double-ended break of the 4-inch jet pump instrument line and determined that the current design of shield door, shield wall, RPV and RPV skirt can withstand the loads under EPU conditions.

Conclusion

The NRC staff has reviewed the subcompartment assessment performed by the licensee and the change in predicted pressurization resulting from the increased M&E 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 the 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 GDC-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 Accident

Regulatory Evaluation

The release of high-energy fluid into containment from pipe breaks could challenge the structural integrity of the containment, including subcompartments and systems within the containment. The NRC staff's review covered the energy sources that are available for release

to the containment and the M&E release rate calculations for the initial blowdown phase of the accident. The NRC's acceptance criteria for mass and energy (M&E) 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

The licensee has performed an M&E release analysis based on GEH GE14 as the principal reference fuel, whereas the BFN units will use AREVA ATRIUM 10XM with potential for some legacy ATRIUM-10 fuel under the EPU conditions. Therefore, an evaluation of the equivalency of thermal parameters and any other differences between the two fuel types is required. In an RAI, the NRC staff requested the licensee to justify (considering the differences in mass, material properties, core flow, decay heat, heat transfer coefficients between the core and the coolant, and any other variations between the two fuel types) why the LOCA M&E release in the containment based on GE14 fuel is bounding and the various containment analysis results based on GE14 fuel M&E release presented in Section 2.6 of the PUSAR remain valid for ATRIUM 10XM or ATRIUM-10 fuel.

In its response dated August 3, 2016 (Reference 30), the licensee stated:

> The safety analysis codes used in the containment analyses, SHEX, LAMB, and M3CPT use neither detailed reactor kinetics nor detailed fuel rod response characteristics. The results of these safety analyses in the short term (M3CPT with LAMB codes) are primarily driven by reactor and containment gross thermal-hydraulic initial conditions (core thermal power, reactor pressure, reactor water level, total core flow, core inlet sub-cooling, containment pressure, containment temperature and containment relative humidity). The results in the long-term (SHEX code) are primarily driven by reactor decay heat, the suppression pool (torus) heat capacity, and the capacity of the containment heat removal system. In the above containment analysis codes, the sensible and latent heat contribution from the fuel assembly mass to the reactor coolant and subsequently to the containment is performed by modeling the fuel mass (uranium oxide (UO2)) and non-UO2 fuel assembly mass (fuel cladding, fuel channel, etc.) as a single node. Both the fuel mass (UO2) and non-UO2 fuel assembly mass assumed in the Browns Ferry containment analyses are approximately 10-percent greater than the actual fuel mass and non-UO2 fuel assembly mass for a Browns Ferry core composed of either ATRIUM-10 or ATRIUM-10XM fuel. The fuel bundle mass for ATRIUM-10XM fuel is slightly greater than the fuel bundle mass for ATRIUM-10 fuel.
>
> Section 2.8.1 of EPU LAR [(Reference 1)] Attachment 8, Fuel Uprate Safety Analysis Report (FUSAR), pages 35 through 37, contains a comparison of a limiting GE14 fuel decay heat profile to a limiting decay heat profile for the ATRIUM-10 fuel type. The comparison used the same analysis basis, and showed the difference in decay heat fraction to be very small. The ATRIUM-10 XM fuel design was shown to have comparable decay heat to the ATRIUM-10

fuel. The table on page 36 of the FUSAR demonstrates that the fission fractions for U-235, U-238, and Pu-239 are very similar between the GE14, ATRIUM-10, and ATRIUM-10 XM fuel types, which further illustrates the lack of sensitivity of decay heat to the fuel type. These comparisons support the conclusion that the GE14 decay heat profile used in the EPU containment analyses adequately bounds the decay heat of ATRIUM-10 and ATRIUM 10XM, or a core containing a mixture of both AREVA fuel types.

Based on the above response, the NRC staff finds it acceptable that the M&E release analysis using the GE14 fuel is bounding because, (a) the licensee analysis assumed 10-percent greater mass for the fuel and non-fuel items so that the initial stored energy is bounding, (b) the decay heat is not sensitive to the fuel type, because the differences are very small.

For the short-term drywell pressure response, the licensee used the LAMB computer code for the 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 48).

The M&E release following a LOCA in containment is discussed above in Section 2.6.1, "Primary Containment Functional Design," of this SE. 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 and guidance 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 the 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 an M&E release for a postulated LOCA.

2.6.4 Combustible Gas Control in Containment

Regulatory Evaluation

Following a LOCA, hydrogen and oxygen may accumulate inside the containment 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 that safety is not impaired by the sharing. Specific review criteria are contained in SRP Section 6.2.5.

Technical Evaluation

As described in UFSAR Section 5.2.6, during normal operation the primary containment atmosphere is maintained at less than 4-percent oxygen by volume, and the remaining is nitrogen. Following a LOCA, hydrogen is evolved within the containment from metal-water reactions, and hydrogen and oxygen are produced by radiolysis of water. If the concentrations of hydrogen and oxygen were not controlled, a combustible gas mixture could be produced. To ensure that a combustible gas mixture does not form, the oxygen concentration is kept below 5-percent by volume, or the hydrogen concentration is kept below 4-percent by volume. The concentration of combustible gases is controlled by the containment atmosphere dilution (CAD) system which maintains the concentration of oxygen in the containment atmosphere below 5-percent by volume by injecting nitrogen. The nitrogen injection requirement depends on the metal-water reaction rate, which depends on the cladding mass. The licensee, in the FUSAR, states that all BFN units will use AREVA ATRIUM 10XM fuel, with the potential for some legacy ATRIUM-10 fuel, under EPU conditions. The licensee stated that [[

]]

For maintaining the required nitrogen concentration inside the containment, the licensee estimated the CAD system start time of 30 hours from the initiation of a DBLOCA under EPU conditions compared to the current time of 37 hours. Since the CAD system is manually operated, the change in start time of CAD does not impact its manual operation because there is a significantly large time for operator's response during the accident.

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:

An increase to the liquid nitrogen minimum storage volume specified in the revised TS 3.6.3.1, which ensures a 7-day supply, is required so the system will continue to have sufficient capability following the implementation of the proposed EPU. Therefore, 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.

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

The RHR system with its containment cooling modes of operation is provided to remove heat from the containment atmosphere and from the suppression pool. 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 ECCS and containment heat removal system pumps; and (2) the analyses of the heat removal capabilities of the RHR heat exchangers. The NRC's acceptance criteria for containment heat removal are based on draft GDC-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 and temperature under accident conditions. Specific review criteria are contained in SRP Section 6.2.2, as supplemented by Regulatory Guide (RG) 1.82 (Reference 174).

Technical Evaluation

2.6.5.1 Suppression Pool Temperature Response Analysis

The purpose of the analysis is to determine the maximum suppression pool temperature response for postulated accidents and events to assure the acceptability of ECCS pump NPSH under EPU conditions. The acceptability of ECCS pump NPSH based on the maximum suppression pool temperature response is evaluated in Section 2.6.5.2 of this SE.

Browns Ferry UFSAR, Section 8.5.3.1 states that the standby alternating current (AC) supply and distribution system is provided with eight emergency diesel generators (EDGs), four for BFN Units 1 and 2, and four for BFN Unit 3. UFSAR Section 8.5.2, states that for the long-term phase, three of the Unit 1 and 2 EDGs, paralleled with the three respective Unit 3 EDGs are adequate to supply all required loads for the safe shutdown and cooldown of all three units in the event of loss-of-offsite power (LOOP) and a DBLOCA in any one unit. Because of the sharing of EDGs, the suppression pool temperature response should be analyzed when LOCA occurs in one Unit concurrent with LOOP in all three Units assuming a worst single active failure (SAF).

The licensee analyzed the suppression pool temperature response for (a) the RSLB DBLOCA, (b) recirculation-pump discharge line break (RDLB) LOCA, (c) SSLB LOCA, and (d) safe

shutdown of the non-accident unit with minimum cooling equipment available. The NRC-accepted GEH SHEX computer code was used for the analysis.

RSLB DBLOCA - Suppression Pool Temperature Response Analysis

The RHR system is used for suppression pool cooling. The system consists of two independent loops, each having two pumps; with the discharge side of each pump connected to a separate heat exchanger. Each RHR loop has an RPV injection point and a return line to the suppression pool. The suppression pool temperature response increases as a result of the EPU because of higher decay heat. The analyses for peak suppression pool temperature response is divided into two phases referred to as the short-term phase and the long-term phase. The short-term phase covers the period up to 10 minutes after the accident initiation for which the analysis does not credit any operator action. The long-term phase covers the period after 10 minutes following the accident initiation for which operator actions are credited. The current licensing basis analysis for the RSLB DBLOCA assumes a worst SAF where only two of the four RHR pumps are assumed to be available during the short-term (first 10 minutes) phase of the accident. However, the current RDLB licensing basis analysis conservatively assumes all four RHR pumps are running during the short-term phase. GEH in the SC 06-01 (Reference 175) describes the following issue regarding the conservatism of the current long-term suppression pool temperature response:

> During a containment analysis in support of an extended power uprate (EPU) evaluation, it was determined that the current design basis and licensing basis for the DBA-LOCA [Design Basis Accident-LOCA] analysis may not consider the worst-case scenario for peak long-term suppression pool temperature. The existing scenario used to evaluate the DBA LOCA long-term suppression pool temperature response assumes loss-of-offsite power along with a single failure of either a battery, or an emergency diesel generator. In this situation, one Residual Heat Removal (RHR) division (pumps and heat exchangers) is lost, and only the minimum emergency core cooling systems (ECCS) and RHR containment cooling pumps being available. This results in minimum suppression pool cooling capability, however, it also minimizes the pump heat added to the suppression pool during the event.
>
> An alternate worst-case accident scenario from the standpoint of pool heatup may exist where there is minimum pool cooling capability but where there is a significantly greater pump heat transferred to the suppression pool. This can occur if a LOOP does not occur or with a LOOP, if the postulated single failure results in one RHR heat exchanger being unavailable but with the maximum number of ECCS and RHR pumps being available. Consequently, the peak suppression pool temperature for this scenario is higher than that determined based on the original design basis.

The licensee addressed the SC 06-01 (Reference 175) issue by assuming all ECCS (four RHR and four CS) pumps are operating during the short-term phase so that the pump heat addition to the suppression pool is maximized, which conservatively maximizes the suppression pool temperature response for the RSLB and RDLB LOCA.

The inputs, initial conditions, and assumptions for the analysis are as follows:

(a) Reactor thermal power is equal to 102-percent of the EPU value to account for the uncertainty in the power measurement.

(b) Decay heat input based on ANS/ANSI 5.1-1979 plus a 2-sigma addition for uncertainty with additional actinides and activation products per GE SIL 636 (Reference 176).

(c) A break area equal to 4.2 ft^2 (equal to the sum of the recirculation suction line area (3.668 ft^2 on one side of the broken pipe) plus the jet pump throat area of 10 jet pump nozzles (0.548 ft^2 for the other side of the broken pipe).

(d) Initial suppression pool volume corresponding to TS low water level with differential pressure control in service.

(e) LOOP concurrent with the initiation of LOCA and during the analysis period.

(f) Initial conditions to minimize the containment drywell and wetwell pressure response while maximizing the suppression pool temperature response.

(g) Initial drywell relative humidity of 100-percent. The licensee stated that the suppression pool temperature response is not sensitive to the initial value of drywell relative humidity.

(h) Containment leakage at the rate of 2–percent of initial weight of containment air volume per day,

(i) MSIV leakage of 150 standard cubic feet per hour (scfh) for all steam lines,

(j) HPCI system is available which starts on either a high drywell pressure or a low RPV water level signal and isolates on low inlet steam pressure to the HPCI turbine.

(k) For the first 600 seconds (short-term phase) from the accident initiation, the RHR system operates in the LPCI mode with all four pumps operating, each having a flow rate of 9,000 gpm, where two pumps inject water into the intact recirculation loop and the other two pumps into the broken recirculation loop. Also for the first 600 seconds, the CS system with all four pumps operating, each having a flow rate of 3,550 gpm, sprays water into the RPV for core cooling. The limiting initial condition of no SAF during the short-term phase allows operation of all low pressure ECCS pumps (four RHR pumps and four CS pumps), which maximizes the pump heat addition to the suppression pool; therefore, addressing the SC 06-01 issue.

(l) There is no RHR service water (RHRSW) flow to the RHR heat exchangers; therefore, heat is not removed from the RHR heat exchangers during the first 600 seconds from accident initiation.

(m) At 600 seconds from accident initiation, operator action is credited. The analysis assumes: (a) one loop of CS, with two pumps, each CS pump throttled to a flow of 3,125 gpm continue to spray makeup water for core cooling, and (b) one RHR loop, with two pumps and two heat exchangers, each RHR pump throttled to a flow of 6,500 gpm is assigned for containment cooling. The limiting condition for the worst SAF is the failure

of one EDG during the long-term phase, which results in only two RHR pumps and two RHR heat exchangers providing long-term containment cooling.

(n) At 600 seconds a conservatively low RHRSW flow of 4,000 gpm at a temperature of 95 °F is initiated to the two heat exchangers in the RHR operating loop.

(o) The K-value for each RHR heat exchanger is 265 BTU/sec-°F.

The licensee analyzed the suppression pool temperature response for the following three RHR cooling modes:

(a) Coolant injection cooling, where RHR flow is cooled by the RHR heat exchanger before being discharged into the RPV;

(b) Containment spray cooling, where RHR flow is cooled by the RHR heat exchanger and then discharged to the containment via the drywell and wetwell spray headers;

(c) Suppression pool cooling (SPC), where RHR flow is cooled by the RHR heat exchangers and then discharged back to the suppression pool.

The licensee performed a sensitivity analysis by perturbing the initial drywell pressure, initial wetwell pressure and initial drywell temperature to both maximize and minimize the peak containment pressure to investigate its effect on the suppression pool temperature response. The study resulted in a short-term (10-minutes from accident initiation) maximum bulk suppression pool temperature of 152.8 °F, and a maximum bulk suppression pool temperature of 179.0 °F in the long-term phase of the accident.

The NRC staff finds the results of suppression pool temperature response for the RSLB DBLOCA acceptable because the analysis is based on conservative inputs and assumptions using the NRC-accepted SHEX computer code.

RDLB LOCA - Suppression Pool Temperature Response Analysis

The licensee performed a suppression pool temperature response analysis for the short-term phase of the RDLB LOCA by using inputs that maximized the suppression pool temperature and minimized the containment pressure. The RDLB LOCA has a break area of 1.94 ft^2 compared to a RSLB LOCA break area of 4.2 ft^2 because of the difference in the diameter between the recirculation pump suction and discharge piping. Another difference between the RDLB and RSLB analysis is that in the former, the RHR system has a runout flow rate of 11,000 gpm per RHR pump in the broken loop that discharges directly into the drywell, and in the latter, the RHR flow is 9,000 gpm per RHR pump that is injected into the RPV. This difference is because the RHR piping interface with the recirculation piping is on the discharge side of the recirculation pump. The CS flow per pump is assumed to be 3,550 gpm. The analysis assumes all four RHR pumps and all four CS pumps are operating, and no RHRSW flow is provided to the RHR heat exchangers and therefore no heat removal by the RHR heat exchangers. The addition of suppression pool water by the RHR and CS systems along with feedwater results in a recovery of the reactor water level. Reactor water heated by decay heat and vessel sensible heat is discharged into the drywell through the break, and subsequently to the suppression pool.

The NRC staff noted that Table 2.6-2a of the PUSAR does not provide the assumptions used for the initiation of the feedwater flow isolation time and the valve closure time for the suppression pool temperature response analysis. The staff requested the licensee to describe the feedwater flow isolation assumptions for the short and long term suppression pool temperature response analyses and how they differ from the current licensing basis analysis. In its response dated June 24, 2016 (Reference 24), the licensee stated that UFSAR Section 14.6.3.3.1, Items e and f describe the feedwater flow assumptions for the DBLOCA short-term containment response and the DBLOCA long term containment response as follows:

e. For the short term containment response analysis, the feedwater flow is assumed to coast down to zero at four seconds into the event. This conservatism is used because the relatively cold feedwater flow, if considered to continue, tends to depressurize the reactor vessel, thereby reducing the discharge of steam and water into the primary containment.

f. For the long term containment response analysis, the reactor feedwater flow into the reactor continues until all the high energy feedwater (water that would contribute to heating the pool) is injected into the vessel.

For the short-term suppression pool temperature response analysis, the licensee referred to Table 2.6-5 of PUSAR which provides a comparison of the inputs and assumptions for the current and the EPU analysis used for the DBLOCA. The comparison shows the EPU analysis assumption for the feedwater flow isolation is the same as in the current analysis. For the long term suppression pool temperature response analysis, the licensee referred to Table 2.6-6 of the PUSAR, which provides a comparison of the inputs and assumptions for the current and the EPU analysis used for the DBLOCA and for the small steam line break (SSLB) LOCA analysis. The EPU analysis uses a more conservative assumption for feedwater flow than the current analysis because more heat is added to the reactor pressure vessel, which is subsequently added to the suppression pool before its peak temperature is reached.

The licensee calculated the short-term (10-minutes from accident initiation) maximum suppression pool temperature to be 152.0 °F. This shows that the short term pool temperature response for the RDLB LOCA is bounded by the short term RSLB LOCA results. Similarly, the long term RDLB LOCA temperature response results are also bounded by the long term RSLB LOCA results. The peak suppression pool temperature results for both the RSLB and RDLB LOCAs are bounded by the peak suppression pool temperature determined for the SSLB LOCA described below. The NRC staff finds the licensee's evaluation for the RDLB LOCA acceptable.

SSLB LOCA - Suppression Pool Temperature Response Analysis

The licensee analyzed the suppression pool temperature response for SSLB areas of 0.01 ft^2, 0.05 ft^2, 0.10 ft^2, 0.25 ft^2, 0.50 ft^2, and 1.0 ft^2 using the GEH SHEX computer code. The most limiting (higher) response was for the SSLB area of 0.01 ft^2. In Table 2.6-6 of PUSAR, the licensee provided a comparison of the input parameter values between the current and the EPU analysis and stated that the assumed initial conditions maximize the suppression pool temperature response. The input parameter values are listed under the heading "Long-Term Drywell Gas Temperature Response Analysis for Equipment Environmental Qualification" in Section 2.6.1 of this SE.

The licensee's evaluation included inhibition of potential interruption of containment cooling in the LOCA BFN unit concurrent with LOOP in all BFN units for which a simultaneous safe shutdown of the non-LOCA Units will be required. The interruption may be caused by the appearance of a false LOCA signal (high drywell pressure concurrent with low RPV level) in a non-LOCA BFN unit during its depressurization for a safe shutdown. The false LOCA signal, if it appears in a non-LOCA BFN unit, would automatically initiate RHR in its LPCI mode for that BFN unit. To prevent such an interruption, the normal action in the plant operating procedure requires operation of hand switches in the main control room that are permanently installed for inhibiting the appearance of a false LOCA signal in the non-LOCA BFN units. The plant operators, in anticipation of the appearance of the false LOCA signal during depressurization, inhibit the signal by operating the switches. Therefore, there is no possibility of containment cooling interruption in the LOCA BFN unit or the non-LOCA BFN units. The licensee stated that the permanently installed hand switches are also used to inhibit a LOCA signal in a LOCA BFN unit if it appears late when core cooling is already established.

The licensee performed an analysis of the SSLB LOCA suppression pool temperature response for cases with HPCI available and with HPCI unavailable and determined the effect of its availability on the limiting peak temperature. For the HPCI available case, its suction source is conservatively assumed to be the suppression pool instead of the condensate storage tank (CST). The HPCI is qualified only for water temperatures up to 140 °F. In an RAI the NRC staff requested the licensee describe the method of preventing the HPCI operation at higher pool temperatures during any SSLB LOCA (not necessarily the most limiting for peak suppression pool temperature) in case the suppression pool temperature exceeds 140 °F before the HPCI isolation pressure is reached. The licensee in its response to an NRC staff's RAI dated June 24, 2016 (Reference 24), stated that the operators are trained to not operate HPCI with suction temperature above 140 °F unless there are no other means for ensuring adequate core cooling during an event or accident. HPCI operation at higher suppression pool temperatures would be prevented by the operator tripping the HPCI turbine and locking out the HPCI auxiliary oil pump.

The assumptions and the events for the SSLB analysis for the suppression pool temperature response are as follows:

(a) Reactor power is 102-percent EPU RTP, concurrent LOOP in all three Units, and single failure to start of one EDG, or the loss of a 4-kV shutdown board.

(b) SSLB occurs with simultaneous reactor scram assumed at time = 0.

(c) The single failure assumption allows only three RHR pumps and three CS pumps to automatically start on either "low RPV level" or "high drywell pressure concurrent with low RPV pressure" in the accident Unit. Because the RPV pressure is higher than the low pressure permissive for RPV injection during the first 10 minutes, the low pressure RHR and CS pumps operate in minimum flow mode, and no injection to the RPV occurs.

(d) The MSIVs start closing at 0.5 seconds and close completely at 3.5 seconds.

(e) For the analysis case with HPCI available, it is conservatively assumed that the HPCI will take suction from the suppression pool (instead of CST), automatically start on either high drywell pressure or low RPV level, and remain available for the duration of the event until the RPV pressure is below 55 psig.

(f) For the analysis case with HPCI unavailable, it is assumed that the HPCI is unavailable from the beginning of the event. The analysis assumes ADS depressurizes the RPV so the low-pressure RHR and CS pumps can provide RPV makeup water.

(g) At 10 minutes into the event, operators secure one RHR pump, the remaining two are also stopped and prepared for the RHR system to be aligned in the containment spray mode.

(h) At 10 minutes into the event, operators secure one CS pump, while the remaining two continue operating.

(i) When the suppression pool temperature reaches 120 °F, operators initiate RPV depressurization at a rate of 100 °F/hour with manual operation of SRVs.

(j) RPV depressurization is completed when RPV pressure reaches 50 psig and is maintained in the hot shutdown condition afterwards. All BFN units are designed so they are stable in the hot shutdown mode.

(k) Wetwell spray can be actuated 60 seconds after the drywell pressure exceeds 17.1 psia, and drywell spray can be initiated when the drywell temperature exceeds 280 °F.

(l) For addressing the concern related to the RHR interruption on "high drywell pressure concurrent with low RPV pressure" LOCA signal, the operators initiate wetwell and drywell spray no sooner than 20 minutes into the event for any break.

In an RAI the NRC staff requested the licensee, for the 0.01 ft^2 and greater than 0.01 ft^2 SSLB LOCAs, define the sequence of events and operator actions for each of these analyses with HPCI available and HPCI not available. The licensee was also requested to state the assumed sequence including the timing of operator actions for each of these analyses. The licensee, in its response dated June 24, 2016 (Reference 24), provided the event time sequence with HPCI unavailable and HPCI available in Tables SCVB-RAI 7-1 and SCVB RAI 7-2, respectively, for all SSLBs analyzed, assuming an initial drywell temperature of 70 °F, which gives the most limiting suppression pool and drywell temperature response. Table SCVB-RAI 7-2 for HPCI available presents the event time sequence for 0.01 ft^2 and 0.25 ft^2 area breaks which are limiting for maximum suppression pool temperature response and maximum drywell temperature response respectively. The highlighted gray events in these tables represent operator actions.

The analysis for the limiting 0.01 ft^2 area break shows that the assumption of the HPCI available gives a more limiting suppression pool temperature response than the assumption of HPCI unavailable. The peak suppression pool temperature for this break with HPCI assumed unavailable was 181.5 °F and with HPCI assumed available was 182.7 °F both analyzed with an initial drywell temperature of 70 °F. The licensee analyzed a sensitivity case assuming an initial drywell temperature of 150 °F for the most limiting break of 0.01 ft^2 with HPCI available and determined the peak suppression pool temperature to be 182.7 °F which demonstrated its insensitivity to the initial drywell temperature.

The NRC staff finds the results of the suppression pool temperature response analysis for the SSLB LOCA acceptable because the analysis is based on conservative inputs and assumptions using the NRC-accepted SHEX computer code. The results show that the suppression pool

temperature response for the SSLB LOCA bounds the response for the RSLB and RDLB LOCAs.

Safe Shutdown of Non-LOCA Unit - Suppression Pool Temperature Response Analysis

In the event of a LOCA in any one BFN unit and a concurrent LOOP in all three BFN units, a simultaneous safe shutdown of the non-LOCA BFN units is required along with mitigation of the LOCA in the BFN unit experiencing that accident. During these events at EPU conditions with a worst single-active failure, the licensee determined the suppression pool temperature response for the non-LOCA BFN unit which has the minimum containment cooling equipment available. The licensee's explanation regarding which cooling equipment as a minimum would be available for the safe-shutdown of the non-LOCA BFN unit is given below.

Browns Ferry Units 1 and 2 share four 4 kV shutdown boards, each supplied by a safety-related EDG during a LOOP. BFN Unit 3 has four dedicated 4-kV shutdown boards each supplied by a safety-related EDG during a LOOP. The BFN Unit 3's 4-kV electrical distribution system allows a BFN Unit 3 EDG to either power a de-energized 4-kV shutdown board of other units, or to operate in parallel with the other units' EDG for powering their 4-kV shutdown board. The worst case single active failure for containment cooling is the loss of a 4-kV shutdown board shared between BFN Units 1 and 2. The licensee stated that this single failure is more severe than loss of an EDG alone because it prevents repowering the de-energized 4-kV shutdown board from one of the BFN Unit 3 EDGs. With the conservative single failure assumption, only three RHR pumps would be available for either core or containment cooling between BFN Units 1 and 2. The LOCA analysis described above assumes that two of these RHR pumps are used for long-term containment cooling in the accident unit. This allows alignment of only one RHR pump and one RHR heat exchanger for containment cooling on the non-accident unit. Due to the LOOP, all BFN units temporarily lose their drywell cooling system because of the stripping of loads from the 4-kV shutdown boards.

The licensee analyzed the suppression pool temperature response during the safe shutdown of the non-LOCA unit for two scenarios: (a) CST available during shutdown, and (b) CST not available during shutdown. For CST available, the analysis assumes the HPCI system automatically starts on a low RPV level with its pump suction from the CST for providing makeup water to the RPV. The system isolates on a low RPV pressure at 150 psig. For CST unavailable, the analysis assumes the HPCI system automatically starts on a low RPV level with its pump suction from the suppression pool for providing makeup water to the RPV. At a suppression pool temperature of 140 °F, the HPCI is secured because it is not qualified for temperatures greater than 140 °F. In both scenarios, the analysis assumes the operators start a single CS pump to provide makeup water to the RPV after the HPCI is no longer available.

The licensee's analysis used the following conservative assumptions and sequence of events:

- Reactor thermal power equal to 102-percent of EPU power.
- Decay heat per ANS/ANSI 5.1-1979 plus 2-sigma adder for uncertainty while including the additional actinides and activation products per GE SIL 636 (Reference 176).
- MSIVs are assumed to be fully closed at 3.5 seconds after event initiation.

- Main steam relief valves (MSRVs) automatically cycle to control RPV pressure.

- Feedwater injection resumes when the RPV pressure is reduced to below 220 psig which ensures that hot feedwater at a temperature equal to or greater than 337 °F (saturation temperature at 100 psig) is injected into the RPV before the suppression pool temperature peaks. The assumption of energy addition by feedwater is conservative because it occurs late during the event when the suppression pool temperature is reaching its maximum value, and therefore results in a higher temperature response.

- At 90 seconds into the event, a minimum of 4 drywell coolers restart as a unit's 4 KV board is re-energized by its EDG.

- At 10 minutes after the event, the operators align one loop of RHR (one RHR pump, one RHR heat exchanger and RHRSW cooling flow of 4500 gpm to the RHR heat exchanger) in the suppression pool cooling mode with a flow rate of 9700 gpm.

- At 20 minutes after the event, operators restart the additional four drywell coolers to provide additional drywell cooling.

- At a minimum of 10 minutes after the event, when the suppression pool temperature reaches 110 °F, the operators initiate manual reactor depressurization and cooldown at a rate of 100 °F/hr.

- Operators inhibit the generation of a false LOCA signal (by actuating permanently installed hand switches in the main control room) prior to depressurizing the RPV below the pressure that would result in a false signal (low RPV pressure concurrent with high drywell pressure).

- MSRVs are operated to further depressurize the RPV to 100 psig and then operators maintain the RPV at this pressure.

- At 100 psig RPV pressure, the RHR system is transitioned from the suppression pool cooling mode to the shutdown cooling (SDC) mode in a period of 20 minutes. During this transition period, there is no cooling of the suppression pool.

- Cold shutdown of the RPV is achieved using the RHR in the SDC mode when bulk RPV water temperature is less than or equal to 212 °F.

The peak bulk suppression pool cooling temperature for the BFN unit with minimum cooling equipment at EPU conditions results are as follows: (a) 185.1 °F with CST available, and (b) 180.0 °F with CST unavailable.

The NRC staff finds the results of the suppression pool temperature response for the safe shutdown of the non-LOCA unit acceptable because the analysis is based on conservative inputs and assumptions using the NRC-accepted SHEX computer code, and using the available options of using and not using pump suction from the CST.

Loss of RHR SDC Event - Suppression Pool Temperature Response Analysis

In an RAI the NRC staff requested, for the determination of peak suppression pool temperature, the licensee justify the assumption that HPCI operation for the case with HPCI suction from the suppression pool is more conservative then the case with HPCI suction from the CST. The licensee in its response dated June 24, 2016 (Reference 24), stated that in the event of a loss of SDC mode of operation of the RHR system, the SDC is performed by either of the following methods: (a) If the HPCI system is assumed available for the entire event, it provides RPV makeup until reactor pressure decreases below the HPCI isolation pressure, after which the CS system provides the makeup water; (b) If the HPCI system is not available, the Automatic Depressurization System (ADS) is used to rapidly reduce reactor pressure to allow the CS system to provide RPV makeup water. In both methods, the analysis assumed 102-percent EPU RTP with the RHR operating in the direct suppression pool cooling mode. The licensee stated that performing the SDC containment response analysis with method (a) (i.e., with suction from either the suppression pool or the CST) would result in a higher suppression pool temperature response, because its analysis with this method results in a slower heat-up of the suppression pool, compared to method (b). A faster heat-up (method (b)) of the suppression pool using the ADS would have lesser integrated heat addition (decay heat plus sensible heat) to the pool than a slower heat-up at the peak suppression pool temperature. In addition, the heat removal rate by the RHR system is less for the slower suppression pool heat-up than the faster suppression pool heat-up. Therefore, method (a) results in a limiting (higher) peak suppression pool temperature.

For the SDC analysis using method (a), the CST temperature is assumed to be fixed at 130 °F (PUSAR, Table 2.6-2b), and the suppression pool temperature increases from 95 °F up to 140 °F, the maximum allowed temperature for HPCI operation. The licensee provided the following explanation for the effect of the difference of HPCI suction temperature when it draws water from the suppression pool compared to when it draws water from the CST:

> Early in the event, the higher CST temperature (130 °F CST temperature versus the initial SP [suppression pool] temperature of 95 °F) would result in a small increase in reactor steam generation from sensible and decay heat due to the higher CST enthalpy. This effect lessens as the SP begins to heat up. Later in the event after SP temperature reaches 130 °F, the lower enthalpy (cooler) of the CST water injected to the RPV would result in less steam generation from sensible and decay heat and ultimately less heat addition to the SP. The net effect on SP temperature response is similar to the response from continuous HPCI operation with suction from the SP. In addition, CST inventory injection to the RPV would ultimately deposit into the SP, which would result in a higher SP level and mitigate the effect of higher SP temperature on ECCS pump net positive suction head (NPSH). The assumption of HPCI operation from the CST would also result in an increase in the SP level response that would mitigate the loss of RHR pump and CS pump NPSH margin due to the 2 °F SP temperature increase for the loss of SDC and SORV [Stuck Open Relief Valve] events. The loss of SDC and SORV events remain non-limiting with respect to ECCS NPSH margin for the RHR and CS pumps.

The analysis results for the peak suppression pool and NPSH margin are provided in the licensee's response dated June 24, 2016 (Reference 24) to a staff RAI.

The NRC staff finds the analysis results acceptable because the licensee conservatively assumed a 102-percent EPU RTP and HPCI pump suction from the suppression pool, which is conservative compared to using the CST as its suction source.

Stuck Open Relief Valve with RPV Isolation Event - Suppression Pool Temperature Response Analysis

For the stuck open relief valve (SORV) event with RPV isolation, the licensee's analysis assumed the HPCI system provides RPV makeup with primary suction from the suppression pool, and the CS system provides the makeup after HPCI isolation at low reactor pressure. The analysis assumed a 102-percent EPU RTP with RHR operating in the direct suppression pool cooling mode. The HPCI system operation with suction from the suppression pool is limited to maximum suppression pool temperature below 140 °F. In an RAI for determination of peak suppression pool temperature, the NRC staff requested the licensee justify that the assumption of HPCI operation for the case with HPCI suction from suppression pool is more conservative than the case with HPCI suction from the CST. The licensee in its response dated June 24, 2016 (Reference 24), provided the analysis results for the peak suppression pool and NPSH margin in Table 2.6.5-2 of its response.

The NRC staff finds the analysis results acceptable because the licensee conservatively assumed 102-percent EPU RTP and HPCI pump suction from the suppression pool, which is more conservative compared to using the CST as the HPCI pump suction source.

Small Liquid Break LOCA - Suppression Pool Temperature Response Analysis

The licensee in its analysis assumed RHR direct suppression pool cooling instead of the containment spray cooling mode. The NRC staff requested the licensee to describe the analysis, the liquid line and its size inside the drywell that would be most limiting, and to explain why the suppression pool temperature response, and the RHR and CS NPSH available (NPSHa) and NPSH margins would be bounded by the same parameters for the SSLB LOCA results. In its response dated June 24, 2016 (Reference 24), the licensee stated the following analysis assumptions: (a) initial reactor power equal to 102-percent of EPU RTP; (b) the same decay heat, relaxation and metal-water reaction energies as assumed for the large DBA LOCA analysis; (c) LOOP; (d) worst single failure to minimize the available containment cooling; (e) the HPCI system is available and starts automatically on high drywell pressure or low RPV level with suction from the suppression pool; and (f) the HPCI system that is qualified only for water temperatures up to 140 °F is therefore secured when the suppression pool reaches that temperature and the reactor is then depressurized to allow the CS system to provide makeup water. The licensee provided the following description of the analysis:

> Automatic starting of ECCS pumps would occur in accordance with their start logic and timing for electrical loading. Operators initiate depressurization of the RPV at 100 °F/hour when SP temperature reaches 120 °F. At no sooner than 10 minutes after the start of the accident, operators would stop all but two RHR pumps and two CS pumps. At no sooner than 10 minutes after the start of the accident, operators would either re-align or start two RHR pumps in suppression pool cooling (SPC) mode (two RHR pumps at 6,500 gpm each with two RHR heat exchangers with a K-value of 265 BTU/sec-°F per heat exchanger). To address concerns related to ECCS interruption caused by subsequent LOCA signal activated on high drywell pressure concurrent with low RPV pressure, it is

assumed that containment cooling is interrupted for 10 minutes prior to the time of the peak SP temperature. RPV depressurization would be terminated when RPV pressure reaches 50 psig. Operators would maintain RPV pressure between 50 psig and 100 psig until shutdown cooling can be restored.

A spectrum (1.0 ft^2, 0.5 ft^2, 0.10 ft^2, 0.25 ft^2, 0.05 ft^2, 0.01 ft^2) of small liquid line breaks are assumed, consistent with the small steam line breaks. The difference between liquid line breaks and steam line breaks is that the liquid line breaks are assumed as un-isolable breaks that occur in the reactor coolant pressure boundary liquid volume versus the breaks being un-isolable breaks that occur in the reactor coolant pressure boundary steam volume for the small steam breaks. Because the break flow is an isenthalpic process, the steam line breaks result in superheated steam discharged to the drywell atmosphere, while the liquid line breaks result in two-phase break flow into the drywell atmosphere. Therefore, the drywell temperature response for the small liquid line breaks is less severe than for the small steam line breaks. The Browns Ferry EOI [Emergency Operating Instruction] entry point for drywell spray (280 °F) is either not reached for the liquid line breaks or the duration of drywell spray operation for the liquid line breaks is much less for the liquid line breaks than for the steam line breaks. Because the non-operation or limited operation of drywell sprays for the liquid line breaks allows a greater holdup of the sensible heat in the drywell, less heat is discharged to the SP [suppression pool] for the liquid line breaks and the peak SP temperature is consequently less for a given liquid line break size than for the same size steam line break.

For the SP temperature response, the limiting liquid line break size of the break spectrum is the smallest break size (0.01 ft^2) consistent with the results of the small steam line break. The smaller break sizes results in slower SP heat-up. With reactor pressure at the time of peak pool temperature the same, the total (integrated) sensible heat addition to the SP remains the same, but the total (integrated) decay heat to the SP at the time of peak SP temperature is greater for the slow pool heat-up. In addition, the heat removed from the SP is less for the slow pool heat-up. Thus, a slower pool heat-up will result in a higher peak SP temperature.

The NRC staff finds it acceptable that the suppression pool peak temperature response for this event is bounded by the suppression pool temperature response for the SSLB LOCA because the non-operation or limited operation of drywell sprays allows a greater holdup of the sensible heat in the drywell and less heat discharged to the suppression pool. Therefore, the peak suppression pool temperature is less for a given liquid line break size than the peak suppression pool temperature for the same size SSLB given in Table 2.6.5-2.

Station Blackout Event - Suppression Pool Temperature Response Analysis

The station blackout (SBO) event occurs when there is a LOOP concurrent with a turbine trip and failure of the onsite emergency AC power system resulting in a reactor scram. The coping duration for this event is 4 hours (i.e., 14,400 seconds). The licensee's analysis assumes the HPCI system initiates at 267 seconds into the event on a high drywell pressure signal with suction from the CST. The HPCI injects makeup water into the RPV and isolates at 641 seconds at high RPV level. From 1,200 seconds to 7,320 seconds into the event, the RPV

pressure is manually controlled using MSRVs. The reactor core injection cooling (RCIC) system, with suction from the CST, initiates adding makeup water to the RPV at 2,683 seconds into the event at low RPV level maintaining the RPV level above the top of active fuel and isolates at 11,194 seconds at high RPV level. At the end of the coping period (14,400 seconds), power is assumed to be available, and the RHR system is initiated in its direct suppression pool cooling mode taking suction from the pool. The licensee used the SHEX computer code for the analysis assuming 100-percent EPU thermal power and decay heat based on the ANS 5.1-1979 standard along with the recommendation in GEH SIL 636 (Reference 176). The analysis assumes RHR heat exchanger hot side flow equal to 6,500 gpm, RHRSW flow of 4,000 gpm, and a K-value of 265 BTU/sec-°F. The peak drywell gas and suppression pool temperatures are determined to be 276 °F and 203.7 °F respectively, which are below the containment structural design limit of 281 °F. The NRC staff finds the analysis acceptable because the containment response for the SBO event under EPU conditions meets the requirements of 10 CFR 50.62.

Anticipated Transient without Scram Event - Containment Pressure and Suppression Pool Temperature Response Analysis

For EPU implementation, the licensee has proposed to increase the isotopic Boron-10 (B-10) enrichment provided by the SLC system. Increasing the B-10 enrichment would increase the rate of negative reactivity inserted by the SLC system and would result in a faster shutdown of the reactor during the anticipated transient without scram (ATWS) event. This results in a reduced heat input into the suppression pool, thereby lowering the suppression pool temperature response. The SLC system shutdown capability is being increased to support the elimination of the CAP credit during an ATWS event.

The licensee analyzed the four most challenging ATWS cases to confirm that the peak containment pressure and suppression pool temperature are below their design limits under EPU conditions. The cases are (a) MSIV closure (MSIVC); (b) pressure regulator failure-open (PRFO); (c) LOOP; and (d) inadvertent opening of a relief valve (IORV). Consistent with the current analysis, the licensee used the May-Witt correlation for the decay heat which is more conservative than the decay heat based on the ANS 5.1-1979 standard plus 2 sigma. The analysis credits the HPCI system with CST suction providing RPV makeup water and does not credit CS system for this purpose. The suppression pool cooling is performed by the RHR pumps. The limiting ATWS case with respect to containment pressure and suppression pool temperature is determined to be the LOOP case for which only two heat exchangers in the ATWS unit are credited for mitigating the event. The licensee used a conservative RHR heat exchanger K-value of 277 BTU/sec-°F, which corresponds to the EPU state point RHRSW flow of 4,500 gpm at 95 °F, RHR flow of 6,500 gpm at a temperature of 173.3 °F (peak suppression pool temperature for the LOOP case), and 5-percent blocked tubes, at the EPU design fouling resistance of 0.001562 hr-ft^2-°F/BTU. The peak suppression pool temperature and containment pressure results for this case are 173.3 °F and 8.7 psig, respectively, which are well below the containment design temperature and pressure of 281 °F and 56 psig respectively.

The ATWS non-LOOP cases credit all four RHR heat exchangers in the ATWS BFN unit, each having a K-value of 259 BTU/sec-°F. Because all four heat exchangers are operating, the system hydraulic resistance in the common RHRSW discharge piping restrict each heat exchanger flow to slightly greater than 3,800 gpm. The analysis is conservative because the K-value used is less than 260.5 BTU/sec-°F corresponding to the following input parameters: restricted RHRSW flow of 3,800 gpm at 95 °F, RHR flow of 6,500 gpm at heat exchanger shell

inlet temperature of 171.8 °F (peak suppression pool temperature for ATWS non-LOOP cases), and 5-percent tube plugging, at the EPU design fouling resistance of 0.001562 hr-ft^2-°F/BTU. Therefore, the containment response for the ATWS event under EPU conditions meets the requirements of 10 CFR 50.62.

Fire Event - Suppression Pool Temperature Response Analysis

The purpose of this analysis is to demonstrate acceptable suppression pool temperature response as a part of the containment integrity evaluation during a fire event. The licensee performed the analysis using the NRC accepted SHEX computer code. This event is considered to be a special event in SECY-11-0014, Enclosure 1 (Reference 177); therefore, consistent with this reference. The licensee used nominal values for some of the input parameters which are as follows: (a) 100-percent EPU RTP, (b) decay heat based on ANSI/ANS 5.1-1979 standards including GEH SIL 636 (Reference 176) recommendations, (c) initial suppression pool temperature of 92 °F, and (d) RHRSW temperature 88 °F. The licensee stated that the RHRSW temperature of 88 °F and the initial suppression pool temperature of 92 °F are nominal values based on BFN plant data over a 7 year period from January 1, 2008, through January 1, 2015; analysis of the data for these parameters show that Browns Ferry operates at least 95-percent of time below these values. For the suppression pool water volume, the licensee conservatively used the volume corresponding to TS low water level with the drywell-to-wetwell differential pressure control in service. The K-value for the single RHR heat exchanger used in the analysis is 290 BTU/sec-°F based on alternate shutdown cooling (ASDC) RHR flow of 7,500 gpm, RHRSW flow of 4,500 gpm, RHRSW temperature of 88 °F and RHR heat exchanger design fouling resistance 0.001562 hr-ft^2-°F/BTU, which is conservative.

In Section 2.5.1.4.2 of updated PUSAR (Reference 37), the most limiting suppression pool temperature response case for a fire event is referred to as Case 4 bounding safe shutdown case. The sequence of events assumed in the analysis as stated in Table 2.5-3 are as given in Table 2.6.5-1 below.

The analysis results show that the peak wetwell gas space and suppression pool temperatures during this event are 209.0 °F and 207.7 °F, respectively, which are below the containment structural design temperature of 281 °F and the torus attached piping design temperature limit of 223 °F. The peak values of drywell pressure and temperature, and wetwell pressure are bounded by the same in other events.

The NRC staff finds the fire event containment analysis acceptable because the licensee's use of conservative input values for some parameters, and realistic values for others (consistent with SECY-11-0014, Enclosure 1 (Reference 177)), provide conservative analysis results.

Table 2.6.5-1
Case 4 Fire Event Sequence

Approximate Elapsed Time	Sequence
0 seconds	• Reactor scram occurs. • MSIVs start to close. • Feedwater pump is tripped. • Drywell coolers are tripped. • Condensate system continues to operate.
3.5 seconds	MSIVs are fully closed. After isolation, MSRVs automatically start to open and close to maintain RPV pressure.
25 minutes	Begin rapid depressurization using three MSRVs. RPV makeup is supplied by the condensate system.
~40 minutes	Condensate inventory available for injection is depleted. Operators secure condensate flow and initiate ASDC using 7,500 gpm of RHR flow in the LPCI mode.
2 hours	RHR heat exchanger is placed in service.
72 hours	Event is terminated

2.6.5.2 ECCS and Containment Heat Removal Pumps NPSH Analyses

The NPSH analysis of the ECCS and containment heat removal pumps, which are the HPCI, RHR, and CS pumps, consists of verifying adequate NPSH margin exists for their satisfactory operation during the DBA and non-design basis events (also called special events). The NPSH margin is defined as the difference between the NPSHa at the pump suction inlet, and NPSH required (NPSHr) during pump operation. The NPSHr, provided by the pump manufacturer, denominated as NPSHr3%, is obtained by shop testing of the pump under controlled conditions. The NPSHr3% varies with the pump flow rate and is determined from the vendor supplied pump curves. 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. SECY-11-0014 (Reference 178) and SECY-11-0014, Enclosure 1 (Reference 177) provides NRC staff guidance for: (1) evaluating the uncertainty in the NPSHr3% due to the differences between the shop testing conditions and the plant operating conditions; (2) the use of 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 rate.

In SECY-11-0014, Enclosure 1 (Reference 177) the following relation between the NPSHr3%, NPSHreff and the uncertainty in NPSHr3% for design basis events is provided:

$$NPSHreff = (1 + uncertainty) \times NPSHr3\%$$

In SECY-11-0014, Enclosure 1 (Reference 177) the following relation between NPSHr3% and NPSHreff for the non-design basis events, which are Loss of RHR SDC, SORV with RPV isolation, fire, SBO, and ATWS is provided:

NPSHreff = NPSHr3%

Consistent with the NRC guidance in SECY-11-0014, Enclosure 1, 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, that is, it conservatively increased the pump flow rates) by a factor of $1/\sqrt{0.97}$ (1.015) to account for the possible reduction of pump total developed head by 3-percent, when NPSHr3% curves are utilized for comparison to NPSHa.

Consistent with the guidance in RG 1.82 (Reference 174), for RSLB DBLOCA, RDLB LOCA, and SSLB LOCA in which fluid is discharged in the drywell, the licensee conservatively adjusted the NPSHa static head term (suppression pool water level head) by subtracting the drywell holdup volume from the initial suppression pool water volume.

In BWR-TP-12-2011 (Reference 179), the BWR Owners Group (BWROG) submitted a generic assessment of the 21-percent uncertainty applicable to the Browns Ferry CS pumps (Sulzer Model 12x16x14.5 CVDS). A generic and plant-specific assessment of the uncertainty term for the Browns Ferry RHR pumps (Sulzer Model 18x24x28 CVIC) was submitted to the NRC in BWR-TP-14-001 (Reference 180).

The containment heat removal analysis considered debris generated from fiber, reflective metal insulation, qualified coatings, dirt/dust, rust flakes, sludge, and unqualified coatings, transported following a LOCA that can cause ECCS strainer head loss. The ECCS strainer design debris load, which was used as an input to the strainer design, is documented in NRC-approved topical report NEDC-32721-P-A (Reference 181). The quantity and characterization of the strainer debris loading is based on the methodology in NEDO-32686-A (Reference 182). GEH letter dated March 24, 2008 (Reference 183), notified the NRC staff of a technical concern with a strainer debris-bed head loss correlation in NEDC-32721-P-A (Reference 181). Because of this concern, the NRC staff requested the licensee to describe the corrected methodology, correlation and their basis for the strainer debris-bed head loss calculation. In its response dated June 24, 2016 (Reference 24), the licensee stated that the three units cited in GEH letter dated March 24, 2008 (Reference 183), as not affected by the strainer head loss correlation are the three BFN units, because the Browns Ferry ECCS strainer debris-bed head loss is primarily caused by reflective metal insulation rather than fibrous and particulate debris. The ECCS suction strainer debris loading for the NPSH evaluations under EPU conditions is consistent with the current analysis for the RSLB DBLOCA event. For all non-LOCA events debris is not generated. The suppression pool temperature increase in these events is caused by the high energy RPV fluid discharge into the pool through MSRV lines T-quenchers.

Following the guidance in SECY-11-0014, Enclosure 1 (Reference 177) and RG 1.82 (Reference 174), for calculating the NPSHa, the licensee did not credit CAP. Instead, the licensee used the maximum wetwell pressure as 14.4 psia for all LOCAs and special events under EPU conditions. Refer to Section 2.6.5.3 of this SE, which provides a discussion of the CAP elimination in the NPSHa analysis.

For calculating the head loss in the suction piping, by modeling the ECCS pump suction ring header and the piping network, the licensee performed hydraulic analysis for each event with all possible pump combinations. The RHR, CS, HPCI and RCIC system pump suction piping are connected to the ring header. The licensee conservatively used the largest calculated RHR and CS pump suction piping and strainer friction loss in the determination of NPSHa for a given event. Table 2.6-4 of the PUSAR (Reference 47) shows the largest RHR and CS pump suction piping and strainer friction loss term for each of the analyzed events. Table 2.6-4 of PUSAR provides the NPSHr3% and NPSHreff values used for the NPSH margin and NPSH margin ratio for all events.

The NRC staff guidance in SECY-11-0014 (Reference 178), Section 6.6.8 states 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. In Section 6.3.3 of SECY-11-0014, the NRC selected a time limit of 100 hours for the time permitted in the zone of maximum erosion rate. Table 2.6-4 of PUSAR shows the licensee's calculated operating times for RHR and CS pumps, operating with NPSH margin ratios (NPSHa/NPSHr3%) less than 1.6, is significantly less than 100 hours. A BWROG report (Reference 184) provides an assessment of the pump impeller service life while operating in the zone of maximum erosion rate. The assessment concluded that the impeller integrity is maintained during the mitigation of short-term RDLB LOCA with a higher pump runout flow, and also during the mitigation of long-term RSLB or RDLB LOCA with flow within their operating range.

The NRC staff finds that the licensee has conservatively analyzed NPSHa and NPSH margin for DBLOCA and special events following the guidance in SECY-11-0014 (Reference 178) and SECY-11-0014, Enclosure 1 (Reference 177) without crediting CAP. The following paragraphs provides specific details for the LOCAs and the special events considered.

RSLB and RDLB LOCA Short-Term Phase - NPSH Analysis

The NRC staff evaluation of the short-term (10 minutes from accident initiation) suppression pool temperature response for RSLB DBLOCA and RDLB LOCA is discussed in Section 2.6.5.1. The short-term peak suppression pool temperature for RSLB DBLOCA is 152.8 °F and for the RDLB LOCA is 152.0 °F. The short-term friction head loss was determined based on RHR and CS pump runout flows. Each RHR pump runout flow was determined to be 9,842 gpm to the intact RPV recirculation loop with 2 pumps operating, and 10,945 gpm to the broken RPV recirculation loop with 2 pumps operating. Each CS pump runout flow was determined to be 3,830 gpm with 4 pumps operating. Using the RHR and CS pump runout flows for calculating the NPSHa friction loss term (for suction strainer, torus ring header, and pump suction piping), and the vendor supplied NPSHr3% at these flows, the licensee determined positive NPSH margin for both pumps for RDLB and RSLB LOCAs. Table 2.6-4a of PUSAR provides the values of RHR and CS pumps NPSHa, NPSHreff, NPSH margin, and the operating time with NPSH margin ratio less than 1.6 for short-term RDLB LOCA. The results presented in this table demonstrate that in the short-term, the RHR and CS pumps have positive NPSH margin with respect to NPSHreff without reliance on CAP. These pumps will therefore continue to perform their safety function during the long-term phase of RDLB or RSLB LOCAs. The NRC staff finds the NPSH analysis for the short-term phase during a LOCA acceptable because consideration of no SAF is conservative as operation of all RHR and CS pumps resulted in a higher suction strainer and piping head loss due to higher flow.

In the unlikely condition of a small negative NPSH margin during short term (caused by a fluctuating flow during pump runout condition), which is not the case as shown in the short term analysis, the licensee referred to the assessment provided in the BWROG report (Reference 185) for Browns Ferry RHR pumps to address this concern. This report provides a technical evaluation of operation of the RHR pump (Sulzer CVIC pump model) at reduced NPSHa conditions, including short periods of operation with the NPSHa less than NPSHr3%. This evaluation addresses the effect on pump flow rate as well as the mechanical impact of low suction head on essential pump components. Section 5.0 "Conclusion" of (Reference 185) states:

> During actual in-situ NPSH testing, a Browns Ferry RHR pump was operated under severe cavitation at low NPSHa values without any reported failures or unreasonable level of vibrations. Based on the vibration magnitudes observed during these tests, the vibration levels that will be reached by the RHR pumps during operation with NPSHa < NSPH3 [NPSHr3%] are expected to be well within the acceptable limits for these pumps. The fact that there was no damage to any of the pump components shows that the cavitation induced pressure pulsations will not result in pump component failure during short-term operation under reduced NPSHa conditions.
>
> As discussed previously, the time during which NPSHa could be less than NPSH3 is short [[ ]] at the beginning of a DBA-LOCA. These Browns Ferry and Peach Bottom RHR pumps were subjected to operation under severe cavitation (NPSHa < NPSH3) conditions in the vendor test facility during NPSHr characterization tests. Since these pumps and their components underwent the NPSH shop tests without sustaining damage or experiencing unreasonable levels of vibrations under similar test facility set-up as the in-situ field set-up, it is reasonable to expect that a short period of low NPSHa operation will not adversely affect the operation of the Browns Ferry and Peach Bottom RHR pumps for a long-term DBA-LOCA mission. This conclusion is also valid for CVIC [model CVIC] pumps of similar frame size, hydraulics and mechanical configuration operating under similar conditions as the Browns Ferry and Peach Bottom RHR pumps. It is important to note that the Browns Ferry and Peach Bottom RHR pumps have a flooded suction that is continually fed by the suppression pool; therefore, the pumps will always have a positive suction head available.

RSLB DBLOCA Long-Term Phase - NPSH Analysis

The licensee listed the following assumptions for the analysis: (a) it used the maximum suppression pool temperature response based on the RSLB DBLOCA discussed in Section 2.6.5.1, (b) the pump NPSHr3% and the frictional head loss term calculation for determining NPSHa assumes flow rates of 6,600 gpm for the RHR pumps and 3,173 gpm for the CS pumps which are about 1.015 times the safety analysis flows, (d) the ECCS suction strainer debris loading is assumed to be the same as in the current analysis of record, and (e) the suppression pool static head calculation does not include the drywell holdup volume of 8,304 ft^3 (water drawdown volume due to break flow and spray operation); the holdup volume being conservative because it includes the water volume held up in the vent headers, and (f) the licensee applied a 21-percent uncertainty in determination of NPSHreff from NPSHr3%. The

results of RHR and CS pump NPSH margin, and the time during which the NPSH ratio is less than 1.6 is given in Table 2.6.5-2 of this SE.

The NRC staff finds the licensee's analysis acceptable because it is based on conservative inputs and assumptions without crediting CAP and the results for NPSH and NPSH margin show that the ECCS pumps will operate satisfactorily to perform their safety function.

RDLB LOCA Long-Term Phase - NPSH Analysis

The licensee stated that the long-term NPSH analysis for an RDLB LOCA was not performed because it is bounded by the long term NPSH analysis for RSLB DBLOCA based on the following reasons: (a) the short-term temperature response for RDLB LOCA is determined to be bounded by the short-term response for RSLB DBLOCA (refer to Section 2.6.5.1 of this SE), (b) for both LOCAs, the number of CS pumps in operation is 2, the number of RHR pumps in operation is 2, and the number of RHR heat exchangers in operation is 2, (c) the pump flow rates, and the cooling water flow is identical for both LOCAs. The NRC staff finds it acceptable that the long-term analysis for the RDLB LOCA is not needed to be analyzed because it is bounded by the long-term analysis of the RSLB DBLOCA for the above reasons.

SSLB LOCA- NPSH Analysis

During the short-term (10-minutes from initiation) SSLB LOCA phase, the RHR and CS pumps are either not operating or are operating at minimum bypass flow and the peak suppression pool temperature is at least 20 °F lower than for the RSLB DBLOCA. Therefore, the NPSH analysis for the short-term is bounded by the short-term NPSH analysis for RSLB and RDLB LOCAs.

For the long-term SSLB LOCA phase, the licensee made the following conservative assumptions for the analysis: (a) it used the maximum suppression pool temperature response based on 0.01 ft^2 area SSLB LOCA (discussed in Section 2.6.5.1of this SE), (b) the pump NPSHr3% and the frictional head loss term calculation for determining NPSHa assumes flow rates of 6,600 gpm for the RHR pumps and 3,173 gpm for the CS pumps, which are about 1.015 times the safety analysis flows, (c) the ECCS suction strainer debris loading is conservatively assumed equal to that assumed in the large break LOCA NPSH analysis, (d) the suppression pool static head calculation does not include the drywell holdup volume of 8,304 ft^3 (water drawdown volume due to break flow and spray operation); the holdup volume being conservative because it includes the water volume held up in the vent headers, and (e) consistent with SECY-11-0014, Enclosure 1 (Reference 177), it applied 21-percent uncertainty in determination of NPSHreff. The results of RHR and CS pump NPSH margin, and the time during which the NPSH ratio is less than 1.6 is given in Table 2.6.5-2 below. For the HPCI available case with 0-percent uncertainty included in NPSHreff, the CS pump NPSH margin is 4.3 feet. For the HPCI not available case with 21-percent uncertainty included in NPSHreff, the CS pump NPSH margin is 0.6 feet.

The NRC staff finds the licensee's analysis acceptable because it is based on conservative inputs and assumptions without crediting CAP and the results for NPSH and NPSH margin show that the ECCS pumps will operate satisfactorily to perform their safety function for the mitigation of SSLB LOCA.

Safe Shutdown of the Non-Accident BFN Units (following LOCA in one BFN unit, and LOOP in all three BFN units) - NPSH Analysis

As discussed in Section 2.6.5.1 of this SE, out of the two non-accident units, the limiting one has a single RHR pump available for suppression pool cooling. Consistent with SECY-11-0014, Enclosure 1 (Reference 177), the licensee assumed 0-percent uncertainty in the NPSHr3% because shutdown of the non-accident BFN unit is a non-design basis event. During this event, suction strainer debris loading, the holdup volume, and spray operation are not of concern because there is no pipe break in the non-accident BFN unit. The RHR pump flow is assumed to be 10,000 gpm that is higher than the RHR pump flow rate of 9,700 gpm assumed in the safety analysis for the suppression pool temperature response. The results of RHR pumps NPSH and NPSH margin, and the time during which the NPSH ratio is less than 1.6 is given in Table 2.6.5-2 below. The NRC staff finds the analysis acceptable because the licensee did not credit CAP, and it used conservatively higher RHR flow than used in the suppression pool temperature response analysis.

Loss of RHR SDC - NPSH Analysis

Consistent with SECY-11-0014, Enclosure 1 (Reference 177), the licensee assumed 0-percent uncertainty in determining NPSHreff because this is a non-design basis event. During this event, suction strainer debris loading, the holdup volume, and spray operation are not of concern because it does not involve a pipe break accident. The licensee assumed RHR flow of 6,600 gpm and CS flow of 3,173 gpm for their NPSHr3% calculation. The results of RHR and CS pumps minimum NPSHa and minimum NPSH margin, and the time during which the NPSH ratio is less than 1.6 is given in Table 2.6.5-2. The NRC staff finds the analysis acceptable because the licensee did not credit CAP, and used conservatively higher RHR and CS flows than used in the suppression pool temperature response analysis.

SORV with RPV Isolation Event - NPSH Analysis

Consistent with SECY-11-0014, Enclosure 1 (Reference 177), the licensee assumed 0-percent uncertainty in determining NPSHreff because this is a non-design basis event. During this event, suction strainer debris loading, the holdup volume, and spray operation are not of concern because it is not a pipe break accident. The licensee assumed RHR flow of 6,600 gpm and CS flow of 3,173 gpm for its NPSHr3% calculation. The results of RHR and CS pumps minimum NPSHa and minimum NPSH margin, and the time during which the NPSH ratio is less than 1.6 is given in Table 2.6.5-2. The HPCI pump NPSH margin at 140 °F suppression pool temperature is 15.8 feet with an assumed HPCI flow rate of 5,000 gpm. The NRC staff finds the analysis acceptable because the licensee did not credit CAP, and used conservatively higher RHR and CS flows than used in the suppression pool temperature response analysis.

Small Liquid Line Break- NPSH Analysis

The NPSHa and NPSH margin for the small liquid break LOCA is bounded by the RHR pump and CS pump NPSHa and NPSH margins reported in Table 2.6.5-2 below for the SSLB LOCA.

SBO Event- NPSH Analysis

Consistent with SECY-11-0014, Enclosure 1 (Reference 177), the licensee assumed 0-percent uncertainty in the NPSHr3% because this is a non-design basis event. During this event,

suction strainer debris loading, the holdup volume, and spray operation are not of concern because it is not a pipe break accident. The licensee assumed RHR flow of 6,600 gpm for NPSH calculation. The results of the RHR pumps minimum NPSHa and minimum NPSH margin, and the time during which the NPSH ratio is less than 1.6 is given in Table 2.6.5-2 below. The NRC staff finds the analysis acceptable because the licensee conservatively maximized the RHR flow for minimizing the NPSHa without crediting CAP, and calculated a positive NPSH margin for acceptable ECCS pump operation during the SBO event.

ATWS Event - NPSH Analysis

Referring to the ATWS event analysis cases described in Section 2.6.5.1 of this SE, the combined effect of the suppression pool temperature, suppression pool level, and the RHR pump suction strainer and piping head loss results in the "Least" value of NPSHa for the MSIVC and PRFO cases and therefore have the least NPSH margin, even though the MSIVC case has a peak suppression pool temperature of 171.8 °F compared to 173.3 °F for the LOOP case. The least margin in the MSIVC and PRFO cases is due to the assumption of all four RHR pumps in operation, which maximizes the pump suction piping head loss term in NPSHa. The licensee's assumption of four RHR pump operation is based on the plant emergency operating instructions (EOIs) to maximize the rate of suppression pool cooling because there being no concurrent event in the non-ATWS BFN units, all RHR loops are assumed available for suppression pool cooling in the ATWS BFN unit during non-LOOP events. Consistent with SECY-11-0014, Enclosure 1 (Reference 177), the licensee assumed 0-percent uncertainty in the NPSHr3% because this is a non-design basis event. During this event, suction strainer debris loading, the holdup volume, and spray operation are not of concern because it is not a pipe break accident. The licensee assumed each RHR pump flow of 6,600 gpm for the NPSH calculation and the CS pumps' operation is not credited during ATWS events. The results of the RHR pumps' NPSH and NPSH margins and the time during which the NPSH ratio is less than 1.6 are given in Table 2.6.5-2. The NRC staff finds the analysis acceptable because the licensee conservatively maximized the RHR flow for minimizing the NPSHa without crediting CAP, and calculated a positive NPSH margin for acceptable ECCS pump operation during the ATWS event.

Fire Event - NPSH Analysis

For the fire event analysis, the licensee submitted a revision to the EPU evaluation, in its letter dated August 3, 2016 (Reference 30), Enclosure 2, from the previously submitted evaluation in PUSAR. Consistent with SECY-11-0014, Enclosure 1 (Reference 177), the licensee assumed a zero-percent uncertainty for the determination of NPSHreff because the fire event is a non-design basis (special) event. However for the suppression pool level, the licensee conservatively assumed the TS minimum water level for NPSH calculation. During this event, suction strainer debris loading, the holdup volume, and spray operation are not of concern because the event does not involve a pipe break. The licensee conservatively assumed ASDC RHR flow of 7,615 gpm for the NPSH calculation which is greater than the 7,500 gpm assumed for the suppression pool temperature response analysis. The results of RHR pumps minimum NPSHa, minimum NPSH margin, and the time during which the NPSH ratio is less than 1.6 is given in Table 2.6.5-2 below. The limiting fire event terminates following initiation of ASDC when safe and stable conditions are achieved. The NRC staff finds the analysis acceptable because the licensee used the TS minimum suppression water pool level and maximized the RHR flow for conservatively minimizing the NPSHa without crediting the CAP and confirmed positive NPSH margin during the event.

Summary of NPSH Analysis

The results of the licensee's RHR and CS pumps NPSH analysis shows positive NPSH margin is available for all accidents and special events without crediting CAP. The ECCS strainer design debris load is considered in the analysis. The pump operating time with a NPSH margin ratio less than 1.6 is much less than 100 hours for any event. The maximum allowed temperature for HPCI operation, with suction from the suppression pool, is limited to suppression pool temperature below 140 °F. These pumps are secured prior to suppression pool temperature reaching 140 °F without any impact on core cooling. With the assumed HPCI flow of 5000 gpm, at the maximum allowed suppression pool temperature of 140 °F, the HPCI pump has a positive margin of 15.8 feet.

Table 2.6.5-2
NPSH Analysis Results

Accident/Event	Peak SP* Temp (°F)	Uncertainty in NPSHr3% (%)	NPSH Margin (NPSHa - NPSHreff) (feet)		NPSH Ratio (NPSHa/NPSHr3%)		Time during which NPSH Ratio <1.6 (hours)	
			RHR Pump	CS Pump	RHR Pump	CS Pump	RHR pump	CS pump
Short-term RDLB LOCA	152.0	21	4.7	2.6	1.5	1.3	<1	<1
Long-term RSLB DBLOCA	179.0	21	8.1	1.9	1.7	1.3	0	<18
Long-term SSLB LOCA	181.5	21	6.8	0.6	1.6	1.2	0	<16
Loss of RHR SDC Event (Note 1)	178.3	0	11.7	9.6	1.7	1.5	0	<1
SORV Event (Note 1)	161.8	0	16.7	14.7	2.0	1.76	0	0
Non-Accident Unit SDC	185.1	0	6.9	8.6	1.3	1.4	<1	<1
Fire Event (Note 2)	207.7	0	0.11	Not-applicable	1.0	Not-applicable	<16	Not-applicable
SBO Event	203.7	0	0.2	Not-applicable	1.0	Not-applicable	<3	Not-applicable
ATWS MSIVC Event	171.8	0	14.2	Not-applicable	1.8	Not-applicable	0	Not-applicable

* Suppression Pool

Notes
1. Results of peak SP temperature and NPSH margin are taken from the licensee's response to the NRC staff RAI in (Reference 24)
2. Revised results provided in the revised PUSAR provided in Enclosure 2 of (Reference 37)

2.6.5.3 Elimination of CAP Credit in NPSH Analyses

The licensee in Attachment 39 (Reference 186) of the LAR (Reference 1) provides the RHR heat exchanger K-values and heat removal rates for postulated accidents and special events so that CAP is not credited in the NPSH evaluation under EPU conditions. The licensee provided Revision 1 of Attachment 39 in (Reference 30). Elimination of CAP credit means that a positive NPSH margin should exist while not crediting the wetwell pressure developed during an accident or a special event in the NPSHa analysis. For this purpose, the licensee proposed to increase the NPSHa, during an accident or a special event, by lowering the vapor pressure at the inlet of the ECCS pumps. This is accomplished by lowering suppression pool temperature response during an accident or a special event. The following changes are proposed for reducing the suppression pool temperature response: (a) change in the RHR heat exchanger K-value, and (b) increase the isotopic B-10 enrichment provided by the SLC system during an ATWS event. The change in the RHR heat exchanger K-value is discussed in the following sub-sections. For a discussion of (b), refer to Section 2.6.5.1 of this SE.

Relationship between Heat Exchanger K-value, Effectiveness and Fouling Resistance

The effectiveness "ε" is a standard heat exchanger text book term, defined as the ratio of actual heat transfer (Q) to the maximum possible heat transfer that can take place in the heat exchanger. During a transient in which the hot side inlet temperature changes with time, while the cold side inlet temperature is constant, such as in the suppression pool temperature response, the actual heat transfer Q is the maximum heat that is actually transferred, and is based on the peak hot side inlet temperature of the heat exchanger. The effectiveness is defined by the following equation:

$$\varepsilon = Q/ [C_{min}*(T_{hi}-T_{ci})]$$

$$Q = m_h*c_{ph}*(T_{hi}-T_{ho}) = m_c*c_{pc}*(T_{co}-T_{ci})$$

The K-value (BTU/sec-°F) of the heat exchanger is defined by,

$$K = Q/(T_{hi}-T_{ci})*3600$$

Therefore the relationship between K-value and effectiveness is given by,

$$K = \varepsilon * C_{min}/3600 \qquad \text{(Equation 1)}$$

The RHR heat exchanger is a vertical single shell and two tube pass (parallel counter flow) type with shell fluid mixed. The algebraic equation for the effectiveness of the heat exchanger used by the licensee taken from "Fundamental of Heat and Mass Transfer" 3rd Edition (Reference 187) is given below. The NRC staff checked and verified the same relationship in Equation 2-20 of "Compact Heat Exchanges" 2nd Edition (Reference 188).

$$\varepsilon = 2 * [1 + C_R + \{(1 + C_R^2)^{0.5}] *[(1 + e^{-\Gamma})/(1 - e^{-\Gamma})\}]^{-1} \qquad \text{(Equation 2)}$$

$$\Gamma = NTU * (1+ C_R^2)^{0.5} \qquad \text{(Equation 3)}$$

$$C_R = C_{min}/C_{max} \qquad \text{(Equation 4)}$$

$$NTU = UA_o/C_{min} \qquad \text{(Equation 5)}$$

$U = Q/(A_o*F*LMTD)$ (Equation 6)

$R_f = 1/U - 1/h_o - (1/h_i)*(A_o/A_i) - d_o/(24*k_w)*\ln(d_o/d_i)$ (Equation 7)

Where,

ε	= effectiveness of the heat exchanger
m_h	= mass flow rate of hot fluid (lb/hr)
m_c	= mass flow rate of cold fluid (lb/hr)
c_{ph}	= specific heat of hot fluid at its bulk average temperature (BTU/lb-°F)
c_{pc}	= specific heat of cold fluid at its bulk average temperature (BTU/lb-°F)
T_{hi}	= inlet temperature of hot fluid (highest temperature during the transient) (°F)
T_{ho}	= discharge temperature of hot fluid (°F)
T_{ci}	= inlet temperature of cold fluid (°F)
T_{co}	= discharge temperature of cold fluid (°F)
C_{min}	= minimum heat capacity = smaller of (m_c*c_{pc}) and (m_h*c_{ph}) (BTU/hr-°F)
C_{max}	= maximum product of mass flow rate and specific heat of fluid (BTU/hr-°F)
A_o	= Effective heat transfer area on outside surface of tubes (ft^2)
A_i	= Effective heat transfer area on inside surface area of tubes (ft^2)
h_i	= Inside (tube-side) film heat transfer coefficient (BTU/hr-ft^2-°F)
h_o	= Outside (shell-side) film heat transfer coefficient (BTU/hr-ft^2-°F)
d_i	= inside tube diameter (ft)
d_o	= Outside tube diameter (ft)
k_w	= Thermal conductivity of tube material (BTU/hr-ft-°F)
Q	= Limiting heat transfer rate at the maximum hot fluid temperature (BTU/hr)
U	= Overall heat transfer coefficient (BTU/hr-ft^2-°F)
LMTD	= Log mean temperature difference (°F)
F	= LMTD correction factor for a single shell, two tube pass
R_f	= Overall fouling resistance (hr-ft^2-°F/BTU)

For a given K-value, the acceptable fouling resistance is calculated for a LOCA or a special event using its state point conditions (flows and temperatures) using Equations 1 through 7.

The test fouling resistance R_f is calculated from Equation 7 using the tested value of U, h_o, and h_i with test uncertainty included.

Current Containment NPSH Analysis

In the current licensing basis fire event NPSH analysis, CAP credit is eliminated by increasing the NPSHa by lowering the vapor pressure at the pump inlet, which is accomplished by lowering the suppression pool temperature response. The method used for lowering the suppression pool temperature response was by assuming an improved thermal performance of the RHR heat exchanger by increasing its K-value from the previous (original) design value of 223 BTU/sec-°F to 265 BTU/sec-°F using the projected heat transfer at its most limiting conditions. The most limiting condition is heat transfer at the peak suppression pool temperature. The previous value of 223 BTU/sec-°F was based on the RHR heat exchanger specification sheets, which specified the original design fouling resistances. The BFN plant-specific RHR heat exchanger testing discussed in the NRC letter dated October 28, 2015, "Browns Ferry Nuclear Plant, Units 1, 2, and 3 - Issuance of Amendments Regarding Transition to a Risk-Informed, Performance-Based Fire Protection Program In Accordance With 10 CFR 50.48(c)" (Reference 160) showed a substantial margin between the original design

and the tested fouling resistance. The licensee used some of this margin to increase its heat transfer capability from its original design value to a revised K-value of 265 BTU/sec-°F. The limiting conditions refer to the state point associated with the current DBLOCA containment NPSH analysis which are as follows: RHR flow of 6,500 gpm, RHRSW flow of 4,000 gpm, RHRSW temperature of 95 °F, 4.57-percent RHR heat exchanger tube plugging, and suppression pool temperature of 187.4 °F. The projected limiting heat transfer based on the LOCA state point and K-value of 265 BTU/sec-°F is 88,200,000 BTU/hour, and the corresponding overall fouling resistance is 0.001517 hr-ft^2-°F/BTU. This fouling resistance corresponds to a K-value of 284.5 BTU/sec-°F at the following Fire Event state point condition: RHR flow of 7,500 gpm, RHRSW flow of 4,400 gpm at 92 °F, and initial suppression pool temperature 95 °F. For a conservative Fire Event containment NPSH analysis, the licensee used the lower K-value of 270 BTU/sec-°F (compared to 284.5 BTU/sec-°F), higher initial suppression pool and RHRSW temperatures of 95 °F and 92 °F (compared to 92 °F and 88 °F) respectively and lesser RHRSW flow of 4,400 gpm (compared to 4,500 gpm).

EPU Containment NPSH Analysis: RHR Heat Exchanger Fouling Resistance

The licensee determined that under the EPU conditions the RHR heat exchanger design basis fouling resistance will be based on the limiting EPU Fire Event. For the mitigation of this event, only one RHR heat exchanger is available. The state point conditions used in analyzing this event are as follows: RHRSW flow of 4,500 gpm at nominal inlet temperature of 88 °F, RHR flow of 7,500 gpm, 4.57-percent of 1,700 tubes blocked, the RHR heat exchanger K-value 290 BTU/sec-°F. This K-value at the above conditions corresponds to a heat exchanger overall fouling resistance of 0.001562 hr-ft^2-°F/BTU. The licensee stated that no modifications are required for the increase in the RHRSW flow from its current analysis flow of 4,400 gpm to the EPU analysis flow 4,500 gpm.

For the mitigation of DBLOCA, two RHR heat exchangers are available. The K-value for each RHR heat exchanger assumed in the analysis is 265 BTU/sec-°F. This value is conservative because it is less than the K-value of 266.4 BTU/sec-°F calculated from the following EPU DBLOCA state point conditions: RHRSW flow of 4,000 gpm at inlet temperature of 95 °F, RHR flow of 6,500 gpm at peak suppression pool temperature of 179.0 °F and 5-percent tubes blocked. The RHR heat exchanger heat transfer capability based on a K-value of 266.4 BTU/sec is 80,559,360 BTU/hr, which exceeds its capability of 80,136,000 BTU/hr at the K-value of 265 BTU/sec-°F assumed in the DBLOCA containment analysis.

Other events, including the small break LOCA, loss of RHR SDC, SORV, and SBO were evaluated using a RHR heat exchanger K-value of 265 BTU/sec-°F as described in Section 2.6.5.1 of this SE.

Revision to the Current License Condition Imposed by Transition to NFPA 805

The NRC imposed a license condition for the implementation of NFPA 805 in the NRC Safety Evaluation dated October 28, 2015 (Reference 160), Section 4.0, item 3 under heading "Transition License Conditions". The safety evaluation refers to the licensee's letter CNL-15-224 dated October 20, 2015 (Reference 189) in which the implementation item number 49 in Table S-3 states the license conditions as follows:

> Revise the program that monitors BFN Residual Heat Removal (RHR) heat exchanger performance for consistency with the assumptions of the NFPA 805

Net Positive Suction Head (NPSH) analysis. The monitoring program shall include verification that the tested worst fouling resistance, with measurement uncertainty added, of all BFN Units 1, 2, and 3 RHR heat exchangers is less than the design value of 0.001517 hr-ft2-°F/BTU and the worst tube plugging is less than 4.57 percent.

The NRC staff, in an RAI requested the licensee propose revisions to the above license condition for EPU implementation, including the frequency of cleaning and testing of the RHR heat exchangers. In response to this RAI, the licensee proposed in its letter dated September 12, 2016 (Reference 33) to add the RHR performance monitoring requirements in the administrative controls section of the Browns Ferry TSs. The licensee proposed a new TS 5.5.14, "Residual Heat Removal (RHR) Heat Exchanger Performance Monitoring Program," as follows:

5.5.14 Residual Heat Removal (RHR) Heat Exchanger Performance Monitoring Program

This program is established to ensure that the RHR heat exchangers are maintained in a condition that meets or exceeds the minimum performance capability assumed in containment analyses, which support not taking credit for containment accident pressure in the NPSH analyses. The RHR heat exchanger testing and determination of overall uncertainty in the fouling resistance shall be in accordance with the guidelines in EPRI report, EPRI 3002005340, Service Water Heat Exchanger Test Guidelines, May 2015. This program establishes the following attributes.

a. The program establishes provisions to periodically monitor RHR heat exchanger thermal performance. The program includes frequency of monitoring and the methodology considers uncertainty of the result.

b. The program establishes and controls acceptance criteria for RHR heat exchanger worst fouling resistance and number of plugged tubes.

c. The program establishes limitations and allows for compensatory actions if degraded performance is observed.

d. Changes to the program shall be made under appropriate administrative review.

e. Details of the program including program limitations, compensatory actions for degraded performance, testing method, data acquisition method, data reduction method, overall uncertainty determination method, thermal performance analysis, acceptance criteria, and computer programs used that meet the 10 CFR 50 Appendix B, and 10 CFR 21 requirements are described in the UFSAR.

The NRC staff considers the addition of the TS Section 5.5.14 as proposed above acceptable in place of the current license condition. The TS requirement ensures that the RHR heat exchangers are maintained in a condition such that the positive NPSH margin would exist,

without depending on the CAP, for the operation of the ECCS pumps during accidents or special events.

Based on the proposed inclusion of TS 5.5.14 in the Browns Ferry TSs, the NRC considers that a change to the EPU design fouling resistance of 0.001562 hr-ft^2-°F/BTU, or the acceptance criteria for the maximum number of blocked tubes (i.e., 4.57 percent of 1,700 tubes), or a CAP credit proposed in the NPSH analysis for a DBLOCA or special events, requires the licensee to perform an evaluation in accordance with the requirements in 10 CFR 50.59.

RHR Heat Exchangers Performance Testing for Fouling Resistance

Between January 2012 and June 2016, the licensee tested each of the 12 BFN Units 1, 2, and 3 RHR heat exchangers, at least once, for determining their as-found fouling resistance. The NRC staff requested the licensee to describe the test setup, instrumentation and their accuracy, method of suppression pool heat-up, data acquisition system, test uncertainty analysis, data reduction method for calculation of the fouling resistance, and the method of as found heat-exchanger inspection for determining the number of plugged tubes and the effective heat transfer area. A summary of the licensee's response in its letter dated September 12, 2016 (Reference 33) to the NRC staff RAI is given below.

The tests were performed according to the licensee's approved procedure that included steps to compare the RHR flow (shell) side and RHRSW flow (tube) side heat transfer rates and to statistically evaluate test data and conservatively account for the uncertainties associated with each test. Prior to May 2015, the tests were conducted consistent with the guidance provided in EPRI Topical Report (TR)-107397, "Service Water Heat Exchanger Testing Guidelines," Final Report, March 1998 (Reference 190). Tests after May 2015, were conducted consistent with the guidance in the updated version EPRI 3002005340, "Service Water Heat Exchanger Testing Guidelines, May 2015 (Reference 191). An outside vendor operating under a 10 CFR Part 50, Appendix B, Quality Assurance program, and 10 CFR Part 21 provided the test instrumentation, data acquisition and data processing systems, test reports and results.

The testing was performed back-to-back with quarterly RCIC surveillance testing. The intent of back-to-back testing was to allow the heat input rate from the RCIC turbine exhaust to the suppression pool to be matched to the removal rate from the suppression pool through the RHR heat exchanger while in the suppression pool cooling mode of operation.

Temporary temperature instruments were installed on the outside surface of the heat exchanger inlet and discharge pipes, underneath the insulation. Temporary differential pressure instruments were connected to the instruments taps from the permanent flow orifice in the RHRSW system piping and flow nozzle in the RHR system piping to measure the respective flow rates. These instruments met the guidance identified in EPRI 3002005340, "Service Water Heat Exchanger Test Guidelines," May 2015 (Reference 191). The instruments were calibrated against standards traceable to the National Institute of Standards and Technology or compared to nationally or internationally recognized consensus standards. The reported calibration uncertainty has a confidence level of 95-percent. The calibration accuracy of the temperature instruments is 0.1 °F, and 0.05 percent of full scale for the differential pressure instruments. The composite systematic uncertainty for the instruments used in measurement of RHRSW and RHR flow rates for the RHR heat exchanger performance tests was calculated using 95 percent confidence analysis techniques. The resulting composite systematic uncertainty from each test

for both RHRSW and RHR flow rates was less than plus or minus (±) 5 percent of measured flow.

The data acquisition system, including the associated software, also complies with the guidance in EPRI 3002005340 (Reference 191). The test data was reduced to calculate the nominal (average) values and uncertainty in each measured parameter. These uncertainties were used to establish the overall uncertainty in the test result. The test result was then compared to the acceptance criteria to determine if the test is satisfactory. The calculation followed the heat transfer test method using the heat transfer at design limiting conditions as the performance parameter. This method is outlined in EPRI Test Report 107397, "Service Water Heat Exchanger Testing Guidelines," dated March 1998 (Reference 190).

Currently the as-found GL 89-13 RHR heat-exchanger inspection for determining the number of unavailable tubes and the effective heat transfer area is performed in accordance with an approved licensee's procedure. In this procedure, a tube with greater than 90-percent area blocked, is considered to be a fully-blocked tube, and a tube area blocked between 75-percent to 90-perecnt is considered to be a partially-blocked tube. The equivalent number of fully-blocked tubes is determined by adding the number of tubes greater than 90-percent blocked to 50-pecent of partially-blocked tubes. The equivalent number of fully-blocked tubes must be less than the maximum blocking limit acceptance criteria. The licensee stated that EPU implementation will not change the method of as-found heat-exchanger inspection for determining the number of unavailable tubes and the effective heat transfer area.

Test Uncertainty Analysis

To determine the test uncertainty, the licensee performed a statistical analysis of the test data by a combination of hand calculation and the computer program PROTO-HX which meets the requirements of 10 CFR Part 50, Appendix B, and 10 CFR Part 21. The statistical analysis followed the guidelines in EPRI reports TR-107397 and its updated version EPRI 3002005340 (Reference 191). These reports describe statistical methods to reduce the test data to a set of nominal values, and estimate the test uncertainty with 95-percent confidence. The combination of random standard uncertainty and systematic standard uncertainty was performed in accordance with guidance in Chapter 4 of EPRI 3002005340 (Reference 191). This guidance is based on the ASME Performance Test Codes (PTC), specifically, ASME PTC 12.5-2000, "Single Phase Heat Exchangers" and ASME PTC 19.1-1985 Part 1, "Measurement Uncertainty: Instruments and Apparatus" (replaced by ASME PTC 19.1-2005, "Test Uncertainty").

RHR Heat Exchanger Performance Test Results

In an RAI, the NRC staff requested the licensee provide the latest as-found test results of all BFN Units 1, 2, and 3 RHR heat exchangers. In its response dated August 3, 2016 (Reference 30), the licensee provided test results in Tables SCVB-RAI 34-1 for Unit 1, SCVB-RAI 34-2 for Unit 2, and in SCVB-RAI 34-3 for Unit 3 RHR heat exchangers. At the time of the test, the heat exchangers had been in use for various lengths of time, from 0.1 years to 4 years, from their previous cleaning. The results of the as-found fouling resistance and number of blocked tubes for the three RHR heat exchangers, which were at the maximum time from their previous cleaning, are given below:

BFN Unit 3 heat exchanger 3C, tested in the as-found condition on January 25, 2012, was at the maximum period of 4 years from its previous cleaning. The tested fouling resistance

(without uncertainty) is 0.000746 hr-ft^2-°F/BTU, the test uncertainty is determined to be 0.000260 hr-ft^2-°F/BTU, and the margin from the current acceptance criteria (0.001517 hr ft^2 F/BTU) is 0.000511 hr-ft^2-F/BTU. The number of fully and partially blocked tubes was found to be 43 and 77, respectively. These values do not include the number of mechanically plugged tubes. The equivalent number of fully-blocked tubes is (43 + 0.5*77) = 81.5. Even though the number of plugged tubes slightly exceeded the acceptance criteria (77 tubes), the NRC staff considers the heat exchanger as degraded but operable for its containment heat removal function, because there is (0.000511*100/0.001517) = 33.7 percent positive margin in the fouling resistance.

The BFN Unit 3 heat exchanger 3D, tested in the as-found condition on October 30, 2015, was at the maximum period of 4 years from its previous cleaning. The tested fouling resistance (without uncertainty) is 0.000625 hr-ft^2-°F/BTU, the test uncertainty is determined to be 0.000296 hr-ft^2-°F/BTU, and the margin from the current acceptance criteria (0.001517 hr-ft^2-°F/BTU) is 0.000596 hr-ft^2-°F/BTU. The number of fully and partially blocked tubes was found to be 12 and 12 respectively. These values do not include the number of mechanically plugged tubes. The equivalent number of fully-blocked tubes is (12 + 0.5*12) = 18. The heat exchanger meets its acceptance criteria for fouling resistance and plugged tubes.

The BFN Unit 2 heat exchanger 2C, tested in the as-found condition on January 8, 2015, was at 3.9 years from its previous cleaning. The tested fouling resistance (without uncertainty) is 0.000868 hr-ft^2-°F/BTU, the test uncertainty is determined to be 0.000289 hr-ft^2-°F/BTU, and the margin from the current acceptance criteria (0.001517 hr-ft^2-°F/BTU) is 0.000360 hr-ft^2-°F/BTU. The number of fully and partially-blocked tubes was found to be 305 and 6, respectively. These values do not include the number of mechanically plugged tubes. The equivalent number of fully-blocked tubes is (305 + 0.5*6) = 308. The fouling resistance has a positive margin of (0.000360*100/0.001517) = 23.7 percent, but the number of tubes blocked (308) is unacceptable. For this issue the licensee provided the following explanation:

> During a July, 2013 inspection of a Residual Heat Removal (RHR) heat exchanger, macrofouling of the inlet side of the heat exchanger from relic Asiatic clamshells was identified. The corrective actions included adding frequent cleaning of the RHRSW Pump Pit to the PM [preventive maintenance] program. A March 18, 2015 inspection of RHR heat exchanger 2C, which found 305 tubes potentially fully obstructed, was the last of the 12 heat exchangers inspected subsequent to the October, 2013 RHRSW Pump Pit cleaning. That is, it was the last inspection which could have found shells that had been introduced into the heat exchanger prior to the October, 2013 RHRSW Pump Pit cleaning. The previous cleaning of RHR heat exchanger 2C was performed in January, 2011. RHR heat exchangers which have been inspected more than once, subsequent to performing the RHRSW Pump Pit cleaning PM [preventive maintenance], have shown a significant reduction in the number of shells found. This provides objective evidence that the RHRSW Pump Pit cleaning PM is effective in reducing the accumulation of shells found during subsequent RHR Heat Exchanger inspections. The issue which caused 305 tubes to be plugged is historical and the corrective actions associated with shells in the RHRSW Pump Pit have resolved the issue.

From the above results, the NRC staff finds acceptable that the tested K-value for heat exchangers 3C and 3D bounds the K-values (at their respective state points) required for mitigation DBLOCA and special events without crediting the CAP in the NPSHa under EPU conditions. Even though operable, heat exchanger 3C is considered degraded. Regarding heat

exchanger 2D, the results are considered historical, and do not apply under its current condition because, as stated by the licensee, corrective actions by preventive maintenance (e.g., cleaning the pump pit) have resolved the issue.

Upon EPU implementation, the licensee will perform RHR heat exchanger testing for as-found fouling resistance under the GL 89-13 program. The testing will be performed in the same manner as the previous tests at a nominal interval of 4 years; not to exceed 5 years. These tests will be conducted consistent with the guidance described in EPRI 3002005340 (Reference 191). The EPU thermal performance test acceptance criteria for an RHR heat exchanger are less than or equal to a fouling resistance of 0.001562 hr-ft^2-F/BTU with no more than 77 tubes mechanically plugged. During thermal performance testing of an RHR heat exchanger, the as-found measured test value will be increased to include the associated test and measurement uncertainty. This resulting value will then be compared to the EPU thermal performance test criteria to verify the fouling resistance acceptance criterion is met. In addition, during the GL 89-13 inspection, the acceptance criteria for the total number of tubes found to be blocked (mechanically plugged plus blocked due to macrofouling) shall be less than or equal to 77. Both the RHR heat exchanger fouling resistance acceptance criterion and the GL 89-13 inspection acceptance criterion must be met for the RHR heat exchanger to meet the EPU thermal performance test acceptance criteria and be demonstrated capable of performing in accordance with assumptions in the containment analyses.

EPU Licensing Basis Parameters for RHR Heat Exchangers

The licensing basis RHR heat exchanger K-values, number of heat exchangers, and the flows and temperatures used for the accidents and special events considered are given in Table 2.6.5-3 below. The calculated fouling resistance based on the K-values given in this table have a significant positive margin when compared with the tested fouling resistance (with uncertainty included). Based on these parameters, CAP credit is not needed for a positive NPSH margin for the RHR and CS pumps for mitigation of these accidents and special events.

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 GDC-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.

Table 2.6.5-3
RHR Heat Exchanger Parameters - EPU Licensing Basis

Accident/ Special Event	RHR Flow per HX* (gpm) (Note 1)	Initial SP** Temp (°F)	Peak SP Temp (°F)	RHRSW		Number of HXs used	K-value for 1 RHR HX (BTU/sec-°F)
				Flow per RHR HX (gpm)	Temp (°F)		
DBLOCA	6,500	95	179	4,000	95	2	265
SSLB LOCA	6,500	95	181.5	4,000	95	2	265
Loss of RHR SDC	6,500	95	178.3	Not provided in LAR	95	2	265
SORV	6,500	95	161.8	Not provided in LAR	95	2	265
SBO	6,500	95	203.7	4,000	95	2	265
ATWS-LOOP	6,500	95	173.3	4,500	95	2	277
ATWS-non LOOP	6,500	95	171.8	3,800	95	4	259
Shutdown of non-LOCA Unit	9,700	95	185.1	4,500	95	1	302
Fire	7,500	92	207.7	4,500	88	1	290

Note 1: Safety analysis flows assumed used for determining suppression pool temperature
*HX – Heat Exchanger
**SP – Suppression Pool

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 M&E 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 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 offsite dose. EPU conditions may affect the heat load on the secondary containment and the secondary containment drawdown time. The drawdown time is the time period following the start of the accident or an abnormal event during which loss of offsite power causes loss of secondary containment vacuum (normally maintained at greater than or equal 0.25 inch vacuum water gauge) which is assumed to result in releases from the primary containment directly to the environment without filtering. SR 3.6.4.1.3 verifies two (out of three) standby gas treatment (SGT) subsystems will draw down the secondary containment to greater or equal 0.25 inch of vacuum water gauge in less than 120 seconds. 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.

Under EPU conditions, the M&E released from the primary to the secondary containment will not change because TS primary to secondary containment leakrate requirements are unchanged from the current leakrate requirements. This ensures that the primary and secondary containment leakage will not be significantly different from the current configuration. In response to the NRC staff's RAI requesting additional regarding the secondary containment temperature and pressure, the licensee, in its letter dated June 24, 2016 (Reference 192), stated that the temperature of the area from where the SGTS takes its suction will increase by less than 2 °F under EPU conditions. The small increase in the suction temperature has an insignificant effect on the SGTS mass flow capability and the drawdown time. The licensee stated that the [[

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The NRC staff finds that with no impact on the leakage from the primary to the secondary containment, and an insignificant increase in the SGTS suction temperature, the current SGTS mass flow capability and the secondary containment drawdown time are unaffected and acceptable under EPU conditions. Therefore, the secondary containment functional design is acceptable for performing its safety function under EPU conditions.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the secondary containment pressure and temperature transient and concludes that the licensee has adequately considered the change of M&E that would result from the proposed EPU. The NRC staff-further concludes that the secondary containment and associated systems will continue to maintain the secondary

containment at the required negative pressure to minimize potential of ex-filtration of air from the reactor building during an accident 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 GDC-10, 40, and 42. Therefore, the NRC staff finds the proposed EPU acceptable with respect to secondary containment functional design.

2.6.7 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 (P-Ts) 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 the EPU does not affect the containment isolation devices and the capability to isolate the primary containment during normal operation or accident conditions. The 10 CFR Part 50, Appendix J, Type C local leak rate test pressure Pa, as defined in 10 CFR Part 50, Appendix J, is affected by the EPU as described in Section 2.6.1 of this SE. However, P_a remains below the containment design pressure.

In Section 2.2.4 of PUSAR (Reference 37), the licensee provided an evaluation of the effects of the EPU on the motor operated containment isolation valve related to GL 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance"; GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves"; and GL 96-05, "Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves." The NRC staff's evaluation is provided in Section 2.2.4 of this SE.

Conclusion

The NRC staff finds that the EPU does not adversely affect system designs for containment isolation capabilities because the containment pressure and temperature, which affect its leakage rate, do not exceed their design limits as evaluated in Section 2.6.1 of this SE. Therefore, NRC staff finds that the requirement of draft GDC-49 continues to be met with respect to containment isolation under the proposed EPU conditions and concludes that the proposed EPU is 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 162), 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 the RHR heat exchangers using service water and whether they have the potential for fouling, which causes degradation in performance. NRC GL 89-13 mandates the licensees to have a program for performing periodic testing and inspection to accomplish and maintain operability of the RHR heat exchangers.

Technical Evaluation

The licensee has previously revised in its letter dated March 16, 1990, "Response to Generic Letter (GL) 89-13 Service Water System Problems Affecting Safety-Related Equipment" (Reference 193), its original response to GL 89-13 cleaning and inspection of the RHR heat exchanger RHRSW side interval from "at least once every cycle" to "at least once every five years." The NRC staff requested that the licensee provide the basis for the change. In response to an NRC staff's RAI, the licensee provided, in its letter dated August 3, 2016 (Reference 33), the following explanation:

> A Chemical Treatment Program was put into service in September of 1996. The chemicals are dispersed throughout the RHRSW System to control corrosion, clam infestation, and water fouling. Inspections conducted, after implementation of the Chemical Treatment Program and prior to submittal of the commitment change described in Reference 1 [LAR], showed a relatively small amount of debris and indicated that the heat transfer surfaces were in good condition. Based on the Chemical Treatment Program and the previous inspection results, TVA revised the inspection and cleaning commitment, as described in the Reference 1 letter [LAR], to the following, "Inspect and clean the cooling water side of these heat exchangers periodically as determined by the preventive maintenance (PM) program." Four years was chosen to be the new inspection and cleaning frequency for the RHR heat exchangers at that time based on the PM program results.

The NRC staff also requested that the licensee provide a revision to its GL 89-13 response applicable to the RHR heat exchangers under EPU conditions. In its response dated August 3, 2016 (Reference 33), the licensee stated that upon EPU implementation, the GL 89-13 inspection and cleaning interval for the RHR heat exchangers will remain the same as the current maximum interval of 5 years (4 years plus 25-percent). Any increase in this interval in the future will be technically justified considering the as-found results of the fouling resistance and the number of blocked tubes. The design value of the RHR heat exchanger fouling resistance is being changed from "0.001517 hr-ft^2-F/BTU" to "0.001562 hr-ft^2-F/BTU" under EPU conditions, and the number of acceptable as-found blocked tubes will remain at its current number of 77 tubes, which is the sum of the number of tubes mechanically plugged and the number of tubes obstructed by macrofouling. Therefore, the EPU thermal performance test acceptance criteria will be the tested as-found fouling resistance, including uncertainty, should be less than or equal to 0.001562 hr-ft^2-F/BTU with no more than 77 tubes (4.57 percent of 1700 tubes) blocked.

The Browns Ferry current GL 89-13 program requires a performance monitoring program, in accordance with a license condition in NRC letter dated October 28, 2015 (Reference 160), Safety Evaluation, Section 3.9.3.3, for all RHR heat exchangers to verify whether their heat transfer capability meets the minimum required for accidents and events so that CAP is not credited in the calculation of NPSHa. Implementation of the performance monitoring program in the new TS 5.5.14 satisfies the license condition; therefore, the license condition can be

deleted. In addition, the licensee proposed to update the UFSAR with the following details to ensure no credit for CAP in the NPSHa calculation under EPU conditions is taken:

1. The EPU DBA-LOCA minimum required heat removal rate is 80,136,000 BTU/hour (hr) per heat exchanger with two heat exchangers in service. The EPU fire event minimum required heat removal rate is 124,966,800 BTU/hr with one heat exchanger in service.

2. The EPU thermal performance test acceptance criteria for an RHR heat exchanger is less than or equal to 0.001562 hr-ft^2-F/BTU with no more than 77 tubes (4.57 percent of 1700 tubes) plugged.

3. The nominal (measured) test result (fouling resistance) including the test and measurement uncertainty will be used for comparison to the EPU thermal performance acceptance criteria.

4. The program includes the following requirements:

    a. Each RHR heat exchanger was performance tested at least once prior to the NFPA 805 implementation date, June 16, 2016.

    b. Upon EPU implementation, each RHR heat exchanger will be performance tested at a nominal interval of four years, not to exceed five years.

    c. The RHR heat exchangers will be periodically inspected and cleaned. The inspect and clean interval for the RHR heat exchangers will be in accordance with the GL 89-13 commitment (i.e., inspect and clean the cooling water side of these heat exchangers periodically as determined by the preventative maintenance (PM) program). The current maximum interval for performing RHR heat exchanger inspection and cleaning is procedurally limited to five years (four years + 25 percent). Any increase in the inspect and clean interval beyond five years would be evaluated in accordance with PM program procedures, GL 89-13 program implementing procedures and TVA programmatic procedure change requirements. Changes to the PM performance interval (frequency) are procedurally controlled and require a technical justification for any increase of the PM performance interval. Inspection results and performance testing results will be used to technically justify extending the inspection and cleaning interval. The as-found inspection acceptance criteria is less than 77 tubes obstructed (sum of the number of tubes mechanically plugged and the number of tubes obstructed by macrofouling).

5. Temporary surface mounted temperature instrumentation for RHR and RHRSW inlet and outlet piping meets the guidance provided in EPRI 3002005340, Service Water Heat Exchanger Test Guidelines, May 2015.

6. Temporary differential pressure instrumentations connected to the instrument taps from the permanently installed RHRSW flow orifices and RHR flow nozzles meet the guidance provided in EPRI 3002005340, Service Water Heat Exchanger Test Guidelines, May 2015.

7. Temporary instrumentation includes a temporary data acquisition system (DAS). The DAS software translates instrument output into data files that may be loaded into analytical software. Time stamped data is collected from each temporary instrument sensor. The DAS, including the associated software, complies with the guidance provided in EPRI 3002005340, Service Water Heat Exchanger Test Guidelines, May 2015.

8. Temporary instruments are calibrated against standards traceable to the National Institute of Standards and Technology or compared to nationally or internationally recognized consensus standards.

9. Test data is analyzed in accordance with EPRI 3002005340, Service Water Heat Exchanger Test Guidelines, May 2015. The analysis determines the overall fouling resistance for the heat exchanger and also determines the associated uncertainty in the test result (fouling resistance).

10. The uncertainty analysis methodology complies with the approach described in EPRI 3002005340, Service Water Heat Exchanger Test Guidelines, May 2015.

11. Data reduction complies with the approach described in EPRI 3002005340, Service Water Heat Exchanger Test Guidelines, May 2015.

12. Computer programs used in the thermal performance analysis are required to meet the 10 CFR Part 50 Appendix B, and 10 CFR Part 21 requirements. PROTO-HX is the computer program used for thermal performance analyses in the RHR Heat Exchanger Performance Monitoring Program.

13. Compensatory measures will be established based upon actual plant conditions. Compensatory measures include entering the condition into the TVA corrective action program, cleaning of the heat exchangers after inspections, determining if more frequent inspections and cleaning are required, and evaluating past operability/functionality when tube plugging and macrofouling acceptance criteria from inspection procedures are not met. The methodology for performing as-found and as-left inspections are provided in TVA Standard Programs and Processes procedures. As-left inspections are procedurally required and ensure that tubes found blocked/obstructed by macrofouling will not be left in the as-found condition.

14. Changes to the program requirements above will be controlled in accordance with 10 CFR 50.59, "Changes, tests, and experiments." Change to the program requirements may be made without prior NRC approval provided the changes do not require a change to the TS requirements and the changes do not require NRC approval pursuant to 10 CFR 50.59.

The NRC staff finds the above proposed changes acceptable, since the licensee provided additional details regarding monitoring and inspections of the RHR heat exchanges in accordance with GL 89-13, which will be included in the Brown Ferry UFSAR.

Conclusion

The NRC staff finds the licensee has re-evaluated the issues associated with GL 89-13 and has taken actions 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. Therefore, the NRC staff finds the licensee's evaluation of GL 89-13 for EPU conditions to be acceptable.

2.6.7.3 Generic Letter 89-16

Regulatory Evaluation

Generic Letter 89-16, "Installation of a Hardened Wetwell Vent" (Reference 194), 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 has installed hardened vents in all BFN units in response to GL 89-16. These vents would relieve the wetwell gas space pressure to the atmosphere during a severe accident sequence resulting from a transient followed by a total loss of decay heat removal. The current vent capacity is sized to exhaust sufficient wetwell gas to prevent the containment pressure from exceeding the primary containment design pressure (56 psig) with a constant heat input equal to 1-percent of 3458 MWt or 34.58 MWt. In response to NRC Order EA-13-109 (Reference 195), before implementation of the EPU, the licensee plans to modify the hardened containment vent system for a capacity of 1 percent of the rated EPU RTP as described in the licensee's letter to the NRC dated August 28, 2014 (Reference 196) and approved by the NRC in a letter dated December 23, 2014 (Reference 197). The vent capacity is consistent with the guidance in NEI 13-02 (Reference 198) endorsed by NRC interim staff guidance dated November 14, 2013 (Reference 199).

Conclusion

The NRC staff finds the licensee's evaluation of the hardened wetwell vent with respect to GL 89-16 requirements acceptable. The NRC staff also considers the licensee's plan for modifying the existing vent according the NRC Order EA-13-109 (Reference 195) prior to implementation of EPU acceptable.

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 163), 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 over-pressurization 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

In an RAI referring to Section 2.6.1.5 of the PUSAR, the NRC staff requested the licensee confirm that all system lines for the containment isolation valves listed in UFSAR Table 5.2-2 were evaluated for the GL 96-06 over-pressurization issue under EPU conditions. The licensee in its response dated June 24, 2016 (Reference 24), stated that all system lines with the containment isolation valves listed in UFSAR Table 5.2-2 have been evaluated for the GL 96-06 over-pressurization issue under EPU conditions. The penetrations susceptible to thermal over-pressurization during DBLOCA conditions do not change at EPU conditions. New penetrations are not added, or any changes to the penetration configuration, or the process lines that pass through them are not performed for EPU.

The following systems are affected by GL 96-06: (a) reactor building closed cooling water (RBCCW) system and drywell cooling system, (b) demineralized water system, (c) drywell floor drain sump, (d) drywell equipment drain sump, and (e) reactor water sampling system. The NRC staff's evaluation of these systems for GL 96-06 under EPU conditions is given below.

RBCCW System and Drywell Cooling System

The RBCCW system piping penetrates the containment to supply cooling water for the drywell coolers. In the event of a DBLOCA or steam line break LOCA concurrent with a LOOP, the RBCCW pumps are load shed, and subsequently restart from the emergency bus. During the short period between the stop and restart of the pumps, voiding due to two-phase flow may cause water hammer in the cooling coils of drywell coolers.

The licensee, in its letter dated September 12, 2016 (Reference 33), revised its response to an NRC staff RAI and the technical evaluation provided in Section 2.6.1.5 of PUSAR (Reference 47) regarding the potential for water hammer in the RBCCW piping for the drywell coolers during a DBA LOCA and a steam line break LOCA. As per the analysis that supports the current response to GL 96-06, the first RBCCW pump is given a start signal 40 seconds after it is shed. In case the first pump fails to start, the second pump will be given a start signal 3 seconds later. The calculated times for the initiation of RBCCW voiding in the drywell cooling system coils are as follows:

Unit 1: 49 seconds for DBA LOCA, and 46 seconds for steam line break LOCA;

Units 2 and 3: 61 seconds for DBA LOCA, and 62 seconds for steam line break LOCA.

The licensee explained that the time of initiation of voiding is less for Unit 1 because (a) its replaced drywell coolers have smaller inner diameter than the tubes in the drywell coolers installed in BFN Units 2 and 3; and (b) the drywell cooler analysis was revised to more accurately represent the heat transfer by the cooler tube fins.

For the DBLOCA, Figure SCVB-RAI 16-1 in the licensee's letter dated August 3, 2016 (Reference 33), shows a comparison of the drywell temperature profiles for the current and the EPU analysis. The licensee stated that based on a minor difference in temperature (less than 2 °F) which lasted only seconds in the drywell temperature profiles and the margin between the RBCCW pump start (43 seconds) and calculated time to boil (61 seconds for BFN Units 2 and 3 and 49 seconds for Unit 1), that voiding will not occur under EPU conditions prior to the restart of an RBCCW pump. For the assumption of a minor difference between the current and the EPU drywell temperature profiles, the licensee provided the following justifications:

> The largest differences in temperatures are seen in the first two seconds following a DBA LOCA. The extent of the temperature difference ranges from approximately 6 °F at 0.02 seconds to approximately 1 °F at 2 seconds. When coupled with the small time duration, this difference is expected to have little effect on the drywell cooling time to boiling.
>
> From 2 seconds to 8 seconds, the temperature difference continues to decrease until EPU conditions are bounded by the temperature profile in the current calculation. The small temperature difference, combined with the small time duration is expected to have insignificant effect on the time to boiling.
>
> For the remainder of the time, the temperature profile associated with EPU conditions is either bounded by, or very close to, the temperature profile from the current calculation.

For the steam line break LOCA, the EPU drywell temperature before the restart time (43 seconds) of the RBCCW pump is bounded by the current maximum drywell temperature used in the drywell cooling coils voiding analysis. The licensee stated that the current analysis conservatively assumes that the drywell atmosphere instantaneously increases at the start of the event from the initial drywell temperature of 150 °F to the peak drywell temperature of 336 °F. The drywell temperature is then assumed to remain at the peak temperature for the duration of the event. The EPU temperature profile, in Figure 2.6-9 of the PUSAR (Reference 37), shows that the drywell temperature response for steam line breaks during the first 100 seconds does not exceed 330 °F. The NRC staff finds it acceptable that the water hammer and two-phase flow in the RBCCW system are not a concern because the RBCCW pump will restart prior to voiding in the drywell cooling coils.

Demineralized Water System

The Demineralized Water System piping that penetrates the primary containment is identified as potentially susceptible to thermally-induced over-pressurization. In an RAI for the demineralized water system, drywell floor drain sump discharge, drywell equipment drain sump discharge, and reactor water sampling system, the NRC staff requested the licensee provide the penetration numbers given in the UFSAR Table 5.2-2 for the piping between the specific containment isolation valves under consideration for GL 96-06. In its response dated June 24, 2016 (Reference 24), the licensee identified X-20 (UFSAR Table 5.2-2) as the containment piping penetration for this system on all three BFN units. For BFN, Unit 1, by a modification, this penetration was cut and capped and some of the piping inside the drywell has been removed. The possibility for pressurization due to heat-up of trapped water in the piping no longer exists for this line. For BFN, Units 2 and 3, this penetration was cut and capped but is still used to supply demineralized water to the drywell during outages. The piping internal to the drywell still exists. The GL 96-06 piping under consideration is between the pipe cap located outside of

containment and the system isolation valves located inside containment. For preventing over-pressurization of the system, the current analysis based on a drywell gas temperature of 336 °F following a LOCA showed that 2.06 gallons of water should be removed from the system prior to power operation. Under the EPU condition, with the slightly higher peak drywell temperature of 336.9 °F, the licensee determined 2.07 gallons of water should be removed from the system. The licensee stated that the Browns Ferry procedures have controls in place to ensure that the demineralized water system header is drained prior to power operation in each cycle. As described in the above licensee's response, the required control in the "Valve Lineup Checklist" of the startup procedure is that the low point valve must be verified open by a first operator and independently verified by a second operator. When the low point valve is left open any trapped water in the pipe will drain to the drywell floor if it expands due to a temperature increase during a LOCA. Under the EPU conditions, the NRC staff finds it acceptable that thermally-induced over-pressurization of the demineralized water system piping will not occur because of the following: (a) proper controls during startup are in place, (b) there is a small difference between the water to be removed from the system under the current and EPU conditions, and (c) the system header is drained before each power cycle. Therefore, the NRC staff finds the EPU response to GL 96-06 is acceptable.

Drywell Floor Drain Sump & Drywell Equipment Drain Sump

As per Browns Ferry UFSAR Section 10.16.1, the function of the drainage systems is to collect and remove from the plant all liquid wastes from their points of origin to the river directly, or, if necessary, to the radioactive waste building, where they are treated and returned for reuse or discharged to the river. The drywell floor drain sump and equipment drain sump piping that penetrates the primary containment are identified as potentially susceptible to thermally induced over-pressurization. In response an NRC staff RAI, the licensee, in its letter dated June 24, 2016 (Reference 24), identified X-18 and X-19 (UFSAR Table 5.2-2) as the floor drain and equipment drain sump piping containment penetrations respectively, on all three BFN units. The containment inboard and outboard isolation valves are both located outside the drywell for floor drain and equipment drain sump discharge piping. Therefore, the trapped water between the isolation valves is not subject to thermal over-pressurization during LOCA conditions. Each sump has two parallel pumps with downstream check valves which connect to a common header before passing through the containment penetration. The GL 96-06 piping under consideration is between the inboard isolation valves located outside containment and the sump pump discharge check valves located inside containment. To prevent over-pressurization of this piping, a 0.06-inch (1/16-inch diameter) hole has been drilled in each sump pump discharge check valve to allow adequate leakage for preventing over-pressurization due to thermal expansion. The current analysis of record calculation, using an assumed constant drywell temperature of 336 °F following a LOCA, showed that an orifice diameter of 0.052-inches was sufficient to relieve the flow associated with thermal expansion in the discharge lines. A slightly higher assumed EPU drywell temperature of 336.9 °F will negligibly increase the flow requirements, and the existing orifices are adequately sized to pass this flow at EPU conditions. The NRC staff finds it reasonable and acceptable that the 0.06-inch diameter orifice is sufficient to prevent over-pressurization of the floor drain and equipment drain sump discharge piping during a LOCA under EPU conditions.

Reactor Sampling System

As per Browns Ferry UFSAR, Section 10.17.1, the reactor sampling system provides representative reactor fluid samples for testing to determine systems and equipment

performance. The system piping that penetrates the primary containment is identified as potentially susceptible to thermally induced over-pressurization. In response to an NRC staff RAI, regarding penetration numbers for the piping under consideration for GL 96-06, the licensee identified, in its letter dated June 24, 2016 (Reference 24), X-41 (UFSAR Table 5.2-2) as the containment piping penetration of this system on all three Units. The inboard and the outboard containment isolation valves of the system are normally closed and are only opened when a sample is required. The GL 96-06 piping under consideration is between the inboard and the outboard isolation valves. The current analysis for thermally induced over-pressurization of the reactor sampling system piping, during a LOCA, is performed using a constant drywell temperature of 336 °F. Under EPU conditions, the small increase in the peak drywell temperature to 336.9 °F will result in a negligible reduction in margin for the prevention of over-pressurization. As the pressure in the piping between the isolation valves reaches approximately 2,546 psig, the disc of the inboard globe isolation valve will lift off its seat and relieve the pressure back to the reactor vessel. In response to an NRC staff RAI, regarding design pressure of the inboard isolation globe valve disc, the licensee stated, in its letter dated June 24, 2016, that the valves were hydrostatically tested by the manufacturer to 3,250 psig and the maximum design pressure calculated for the interfacing piping per the design basis code of record is 4400 psig at 336 °F. The reactor side piping design pressure is 1,326 psig. The opening (lifting of the valve disc) of the inboard globe valve will be caused by the thermally-induced pressure, between the inboard and outboard isolation valves, that will generate a force on the disc which exceeds the force of the spring pre-load plus the force due to upstream side (reactor side) pressure. The licensee calculated the opening pressure equal to 2,546 psig by conservatively assuming the reactor side pressure as 1,326 psig which is the same as the piping design pressure. The NRC staff agrees that the globe valve opening pressure of 2,546 psig is conservative at EPU conditions because it is calculated based on the higher reactor side pressure (1,326 psig) than the reactor pressure during a DBA LOCA or steam line break LOCA. The NRC staff finds it reasonable and acceptable that thermally-induced over-pressurization of the piping between the isolation valves will not occur.

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) draft GDC-40, 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.

The licensee indicated (Reference 47) that draft GDC-40 reflects a part of the current licensing basis for the control room habitability system at Browns Ferry, in that components required to function after design basis accidents (DBAs) or abnormal operational transients, are designed to withstand the most severe forces and environmental effects, including missiles from plant equipment failures, without impairment of the components' performance capability. The licensee indicated that the 10 CFR Part 50, Appendix A final GDC-19 is applicable to Browns Ferry as described in "Browns Ferry Nuclear Plant, Units 1, 2, and 3 - Issuance of Amendments Regarding Full-Scope Implementation of Alternative Source Term," dated September 27, 2004 (Reference 200).

Technical Evaluation

The main control room habitability system maintains the control room habitable during normal plant operation, DBA conditions, and anticipated operational occurrences (AOOs) by providing filtered air for personnel ventilation and pressurization of the control room envelope.

The control room emergency ventilation system (CREVS) processes outside air needed to provide ventilation and pressurization for the control room habitability zone (CRHZ) during isolated conditions. When the CRHZ is isolated, a fixed amount of outside air is processed through a high-efficiency particulate air (HEPA) filter bank, air heater, charcoal adsorbers, and post filters. A seismically-qualified safety-related CREVS, composed of two redundant trains, is provided in the Unit 2 control bay area. This system of filtered outside air aids in positive pressurization of the CRHZ with respect to the outdoors.

The licensee indicated that the "Iodine Intake" of the main control room habitability system meets the CLTR disposition. The licensee stated in NEDO-33860, Revision 0, Section 2.7.1, "Control Room Habitability System" (Reference 47) that the radiological impact of the 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 Browns Ferry for which the radiological analysis for DBAs was performed at 102 percent (in the NRC letter dated September 27, 2004 (Reference 200)) of the EPU power level for all the DBAs currently documented in Section 14.6 of the BFN Units 1, 2, and 3 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 the 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 potential of increased effects from toxic and radioactive gases that 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 GDC-19 and draft GDC-40. 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 (SGTSs) and emergency or post-accident air-cleaning systems) for the fuel-handling building, control room, shield building, and areas containing ESF components. For each ESF atmosphere cleanup system, the NRC staff's review focused on the effects of the proposed EPU on system functional design, environmental design, and provisions to preclude temperatures in the adsorber section from exceeding design limits. The NRC's acceptance criteria for ESF atmosphere cleanup systems are based on (1) GDC-19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent, to any part of the body, for the duration of the accident; (2) GDC-41, insofar as it requires that systems to control fission products released into the reactor containment be provided to reduce the concentration and quality of fission products released to the environment following postulated accidents; (3) GDC-61, insofar as it requires that systems that may contain radioactivity be designed to assure adequate safety under normal and postulated accident conditions; and (4) GDC-64, insofar as it requires that means be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including AOOs, and postulated accidents. Specific review criteria are contained in SRP Section 6.5.1 and other guidance provided in Matrix 7 of RS-001.

The licensee indicated in NEDO-33860 (Reference 47), and the NRC staff confirmed, that draft GDC-17 and draft GDC-70, both reflect a part of the current licensing basis for ESF Atmospheric Cleanup Systems at Browns Ferry, as follows: (1) draft GDC-17 is applicable insofar as it requires plant radiation and process monitoring systems to monitor the significant process parameters and the plant environmental effluents to effectively sense abnormal conditions and initiate the ESFs; and (2) draft GDC-70 is applicable insofar as it requires the plant to establish effluent release limits and to identify the means of controlling the releases within these limits. The licensee indicated, and the NRC staff confirms that the 10 CFR Part 50 Appendix A final GDC-19 is applicable to Browns Ferry as described in "Browns Ferry Nuclear Plant, Units 1, 2, and 3 - Issuance of Amendments Regarding Full-Scope Implementation of Alternative Source Term," dated September 27, 2004 (Reference 200).

The licensee stated that there is no draft GDC directly associated with final GDC-41. The NRC staff notes that final GDC-41 pertains to "containment atmosphere cleanup" and that the Browns Ferry primary containment houses no ESF atmosphere cleanup system.

Technical Evaluation

One of the two ESF atmosphere cleanup systems at Browns Ferry is the control room ventilation system. The acceptability of this system under EPU conditions is addressed in Section 2.7.1 of this SE. The second ESF atmosphere cleanup system is the SGTS.

The SGTS provides a means for minimizing the release of radioactive material from the containment to the environs by filtering, monitoring, and exhausting the air from any or all zones of the reactor building and maintaining the building at a negative pressure during containment isolation conditions. By exhausting to the plant stack, an elevated release path is assured for airborne particulates and halogens. By preventing the ground level release of airborne particulates and halogens, the SGTS limits offsite dose following a postulated DBA.

The basic system consists of a suction duct system, three filter trains and blowers, and a discharge vent system. The suction duct system exhausts from the normal ventilation exhaust duct of each of the three reactor zones ahead of the isolation valves and from the refueling zone independent of the normal ventilation system. The three filter trains and blowers are arranged in parallel and are located in two SGTS Buildings. In the SGTS building containing two filter trains and blowers, each blower is normally aligned with its respective filter train, but either blower can be used with either filter train. The third train is located in the second building. All three trains share a common suction manifold. Therefore, each of the three trains is connected to all three reactor zones and the refueling zone.

The licensee also indicated total post-LOCA iodine loading on the charcoal adsorbers increases proportionally with the increase in core iodine inventory. This inventory increases with core thermal power. However, it was stated in the LAR that sufficient charcoal mass is present so that the post-LOCA iodine loading on the charcoal does not increase decay heating such that operation of a filter train is challenged or that there is a threat of charcoal ignition.

The licensee stated, in its letter dated May 20, 2016 (Reference 19), in response to an NRC staff RAI that the SGTS will be the ventilation system in operation for the reactor building post-LOCA. The Browns Ferry SGTS trains take suction from the refuel floor atmosphere for evacuating and maintaining the Browns Ferry secondary containment at negative pressure following a LOCA. The reactor building pressure increase, due to the small increase in temperature that results from EPU, is insignificant. Therefore, the NRC staff has determined that the SGTS is adequate to handle the increased heat load in the reactor building, post-LOCA, at EPU conditions.

The evaluation of the flow performance of the 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. No credit is taken for SGTS charcoal adsorption for any DBA. Credit is taken for HEPA filter removal of 90 percent of the particulate activity in the DBA LOCA analysis.

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 draft GDC-17, final GDC 19, and draft GDC-70. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the ESF atmosphere cleanup systems.

2.7.3 Control Room Area Ventilation System

Regulatory Evaluation

The function of the Control Room Area Ventilation System (CRAVS) is to provide a controlled environment for the comfort and safety of control room personnel and to support the operability of control room components during normal operation, AOOs, and DBA conditions. The NRC staff'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 CRAVS 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 and other guidance provided in Matrix 7 of RS-001.

The licensee indicated in NEDO-33860 (Reference 47), and the NRC staff confirmed, that draft GDC-40 and draft GDC-70, both reflect a part of the current licensing basis for the CRAVS at Browns Ferry, as follows: (1) draft GDC-40 is applicable insofar as it requires components, which are required to function after DBAs or abnormal operational transients, to be designed to withstand the most severe forces and environmental effects, including missiles from plant equipment failures, without impairment of their performance capability; and (2) draft GDC-70 is applicable insofar as it requires the plant to establish effluent release limits and to identify the means of controlling the releases within these limits. The licensee indicated, and the NRC staff concurs, that the 10 CFR Part 50 Appendix A final GDC-19 is applicable to Browns Ferry as described in "Browns Ferry Nuclear Plant, Units 1, 2, and 3 - Issuance of Amendments Regarding Full-Scope Implementation of Alternative Source Term," dated September 27, 2004 (Reference 200).

Technical Evaluation

The CRAVS maintains temperature and humidity conditions suitable for personnel comfort and for reliable equipment operation inside the control room envelope. The system also maintains the control room envelope at positive pressure to inhibit air infiltration.

Cooling of the atmosphere in the main control room is provided by a recirculation air system with refrigeration units. During normal operation, a small stream of makeup air drawn through dust filters is used to maintain a slight positive pressure in the control room. Upon receipt of a primary containment isolation signal or high radiation signal, the normal control room pressurization and makeup network is automatically isolated from the control room habitability zone. This same signal automatically starts the operation of the CRAVS.

The licensee stated in updated PUSAR (Reference 37) 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 no electrical or electronic equipment is being added inside the control room envelope except for some control and indication signals. The licensee stated that the increased amperage effect from additional control and indication signals is insignificant in comparison to the total control room heat load.

The licensee stated in updated PUSAR (Reference 37) that the change of conductance of heat through the building structure to the control room envelope is expected to increase only slightly due to EPU conditions. The NRC staff requested additional information about the causes of the increased conductance of heat. The licensee responded in its letter dated May 20, 2016 (Reference 19), that the control room structure is situated between the turbine building and reactor building structures. During EPU normal operating conditions the additional heat loads within the turbine building include: (a) the addition of a tenth condensate demineralizer which will cause the filter/demineralizer vessel area to increase 5.3 °F; and (b) the installation of larger condensate pump (CP) motors [900 horsepower (HP) to 1250 HP] and larger condensate booster pump (CBP) motors [1750 HP to 3000 HP] that will cause an increase in the area temperature by a maximum of 7.3 °F. The effects of additional heat loads within the reactor building, due to an increase in feedwater temperature, include: (a) the drywell temperature is expected to increase by 0.12 °F; and (b) the main steam valve vault temperature is projected to increase by 0.5 °F. The NRC staff finds this response acceptable, since the licensee explained how conductance of heat within the control room area ventilation system will increase due to EPU conditions.

The NRC staff notes the updated PUSAR Table 2.7-1 (Reference 37) "EPU Effect on Ventilation Systems" summarizes the "EPU Effect" on the CRAVS with the words "Negligible effect due to EPU. No process temperature changes in the Control Room/Control Building." Accordingly, as a result of the EPU, the licensee indicated that no changes have occurred or will occur to the control room HVAC system configuration or system parameters. The licensee also stated in the updated PUSAR (Reference 37) that there is no increase in toxic gas or asphyxiant gas release under EPU conditions. 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 Section 2.7.1 of this SE.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ability of the CRAVS to provide a controlled environment for the comfort and safety of control room personnel and to support the operability of control room components. The NRC staff concludes that the licensee has, for the conditions of the proposed EPU, adequately addressed the issue of any increase in the amounts of toxic and radioactive gases that would result from normal operation, AOOs and DBA conditions. Furthermore, for the EPU conditions, the NRC staff concludes that the licensee has adequately addressed any associated changes to

parameters affecting environmental conditions for control room personnel and equipment. In summary, the NRC staff concludes that operating under EPU conditions neither (1) significantly affects the CRAVS operation during normal operation, AOOs and DBA conditions; nor (2) impacts the system's capability to perform its required functions. Accordingly, the NRC staff concludes that the CRAVS will continue to provide an acceptable control room environment for safe operation of the plant following implementation of the proposed EPU. The NRC staff also concludes that the system will continue to suitably control the release of gaseous radioactive effluents to the environment. Based on this, the NRC staff concludes that the control room area HVAC system will continue to meet the requirements of final GDC-19, draft GDC-40 and draft GDC-70. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the CRAVS.

2.7.4 Spent Fuel Pool Area Ventilation System

As stated in Section 2.7.4 of the PUSAR (Reference 47), Browns Ferry design does not contain a spent fuel pool (SFP) area ventilation system. Ventilation for the SFP area is provided by the reactor building ventilation system under normal conditions. The SGTS provides ventilation in this area during abnormal plant operations (accident conditions). The reactor building ventilation system is evaluated in Section 2.7.5 of this SE. The SGTS is evaluated in Sections 2.5.2.1, 2.6.6, and 2.7.2 of this SE.

2.7.5 Reactor, Turbine, and Radwaste Buildings Ventilation Systems

Regulatory Evaluation

The function of the reactor, turbine, and radwaste buildings ventilation system is to maintain ventilation in their buildings, 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 these systems are based on draft GDC-70, 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 consist mainly of heating, cooling supply, exhaust, and recirculation units in the turbine building, reactor building, radwaste building, and the drywell. The airborne radioactive material concentration in the reactor building is controlled by the reactor building ventilation system during normal operation. The licensee indicated that the "Power Dependent HVAC Performance" of the "Reactor, Turbine, and Radwaste Building Ventilation Systems" meets the CLTR (Reference 48) disposition. 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, 2.6.6, and 2.7.2 of this SE.

The licensee provided the following information in Section 2.7.5 of the updated PUSAR (Reference 37):

- Heat load increase in the drywell is not considered significant, and is within existing system margin. The projected drywell temperature increase is less than 0.5 °F.

- Main steam tunnel (MST) temperature increase will be less than 0.5 °F at EPU conditions due to an increase in feedwater temperature.

- The modification that installed a reactor recirculation system variable flow drive (VFD) to replace the original reactor recirculation system motor-generator sets, resulted in a reduced heat load on the reactor building HVAC system.

- The effect of the EPU on the turbine building ventilation system required no major HVAC system modifications. Increases in process temperatures result in a slight temperature increase. The turbine building is not an EQ zone. The design of the turbine building HVAC system is adequate to handle an increased heat load.

- The effect of the EPU on the radwaste building ventilation system is negligible.

- Monitoring of the radwaste building exhaust and the turbine building exhaust is not affected by the EPU.

- Monitoring of the turbine gland sealing system and the mechanical vacuum pump system are not affected by the EPU.

The NRC staff requested additional information about the effects of EPU implementation on the current engineering heat load analysis for the reactor building. More specifically, the staff inquired whether the reactor building HVAC system was adequate to handle the increased EPU heat load.

The licensee responded in its letter dated May 20, 2016 (Reference 19) that following an accident at EPU conditions, the most limiting reactor building room is the Unit 3 torus room because the temperature increases from 134.0 °F to 140.0 °F. TVA evaluated the effect of the EPU drywell temperature response profiles on the reactor building (secondary containment) temperature response. The results of the evaluation showed a maximum increase of less than 6 °F (i.e., Unit 3 torus room) for all the reactor building rooms and the reactor building general area, and a 2 °F maximum increase in the refuel floor area temperature.

The licensee further stated that the reactor building area temperatures following a LOCA are, in most cases, less than the area temperatures resulting from the design basis steam line breaks in the reactor building. The effects of the increase in area temperatures resulting from the steam line breaks have been taken into account with an environmental qualification (EQ) review of the equipment in the reactor building.

The SGTS will be the ventilation system in operation for the reactor building post-LOCA. The Browns Ferry SGTS trains take suction from the refuel floor atmosphere for evacuating and maintaining the Browns Ferry secondary containment at negative pressure following a LOCA. The reactor building pressure increase due to the small increase in temperature from EPU implementation, is insignificant. Therefore, the SGTS is adequate to handle the increased heat load in the reactor building, post-LOCA, at EPU conditions.

The NRC staff requested additional information about the effects of EPU implementation on the current Turbine Building heat load analysis and on the turbine building HVAC system. More

specifically, the staff inquired whether the turbine building HVAC system was adequate to handle the increased EPU heat load.

The licensee responded in its letter dated May 20, 2016 (Reference 19) that three changes to equipment, as required by EPU implementation, impacted the turbine building heat load analysis and the operation of the turbine building HVAC system. In particular, larger CP motors (900 HP to 1,250 HP) and larger CBP motors (1,750 HP to 3,000 HP) were installed in the turbine building. Installation of the larger CP motors and the larger CBP motors, along with the associated process piping temperature increase, added 688,155 BTU/hr to the CP/CBP areas. This increase in heat load, along with the past convention of operating one air handling unit (AHU) in each area, resulted in an area temperature increase of 7.3 °F. This CP/CBP area temperature increase resulted in the only change made to the turbine building HVAC system as a result of EPU implementation. The change consisted of installing modifications to facilitate the parallel operation of existing redundant AHUs in the CP and CBP areas. The effect of running two AHUs in parallel in each area versus one AHU is that the temperature increase, from the new CP/CBP motors and associated process piping, is reduced from 7.3 °F to 0.9 °F. The third change to equipment in the turbine building, as necessitated by EPU implementation, consisted of installing a tenth condensate demineralizer. The installation of the tenth condensate demineralizer added 33,771 BTU/hr to the condensate filter demineralizer area. This increase in heat load resulted in a temperature increase in the area of 5.3 °F.

In its letter dated May 20, 2016 response to the NRC staff RAI, the licensee concluded that the design of the turbine building ventilation system is adequate to handle the increase in heat load from all three of the turbine building equipment changes resulting from EPU implementation.

In summary, the power dependent HVAC performance meets all CLTR (Reference 48) dispositions. Accordingly, 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 ventilation 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, control the concentration of airborne radioactive material in these areas, and control the 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 ventilation systems will continue to meet the requirements of draft GDC-70. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the reactor building, turbine building, drywell and radwaste building ventilation systems.

2.7.6 Engineered Safety Feature Ventilation System

Regulatory Evaluation

The function of the engineered safety feature ventilation system (ESFVS) is to provide a suitable and controlled environment for ESF components following certain anticipated transients and DBAs. The NRC staff's review for the ESFVS focused on the effects of the proposed EPU

on the functional performance of the safety-related portions of the system. The NRC staff's review also covered (1) the ability of the ESF equipment in the areas being serviced by the ventilation system to function under degraded ESFVS performance; (2) the capability of the ESFVS to circulate sufficient air to prevent accumulation of flammable or explosive gas or fuel-vapor mixtures from components (e.g., storage batteries and stored fuel); and (3) the capability of the ESFVS to control airborne particulate material (dust) accumulation. The NRC's acceptance criteria for the ESFVS are based on (1) 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) draft GDC-70, insofar as it requires that the plant design includes 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 electric board room and battery rooms for Unit 3, the standby diesel generator rooms, and the emergency core cooling system (ECCS) pump rooms (residual heat removal, high-pressure coolant injection, core spray (CS), and reactor core isolation coolant) 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 during normal operation, during AOOs, or after postulated accidents.

The licensee stated in Section 2.7.6 of PUSAR (Reference 47):

- During normal operation, the engineered safety feature HVAC systems serving these areas are unaffected by the EPU because the process temperatures remain bounded by the CLTP conditions.

- The design basis post-LOCA reactor building temperatures will not increase with EPU. Increase in heat loads and temperatures in the ECCS pump rooms are negligible.

- There were no major equipment modifications required as a result of EPU in the electric board room and battery rooms. Therefore, design heat loads in these rooms will not change with EPU.

- The standby diesel generators remains below rated capacity and there is no electrical loading or process temperature change within this area. Therefore, there is no increase in design basis heat load for this area.

- The effect of EPU on ESFVS was negligible. While some electrical operational loads may increase slightly, the cumulative loads will stay below design load limits.

In summary, the power dependent HVAC performance meets all CLTR (Reference 48) dispositions. Accordingly, 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 notes that the ESF HVAC systems do not function to control the concentration of airborne radioactive material within the areas served by these HVAC systems. The control of the concentration of airborne radioactive material in the secondary containment during AOOs and after postulated accidents is accomplished using the SGTS described in Sections 2.5.2, 2.6.6, and 2.7.2 of this SE. Based on this, the NRC staff concludes that the ESF HVAC systems will continue to meet the requirements of final GDC-17, draft GDC-40, draft GDC-42 and draft GDC-70. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the ESFVS.

2.8 Reactor Systems

All three BFN units are of the BWR/4 design with a Mark I containment. The EPU will increase the operating power from the CLTP of 3458 MWt to 3952 MWt, which is an increase of approximately 14.3 percent above the CLTP, and approximately 20 percent above the OLTP level of 3293 MWt. The proposed Browns Ferry EPU is based on no increase in reactor pressure. The NRC has previously approved several BWR EPUs with no increase in reactor pressure. It is assumed in the constant pressure EPU for BWRs that the additional core power is obtained by raising the average bundle power, and that the peak bundle power should remain essentially the same. However, past BWR EPU operations have shown that peak bundle power can increase by a limited amount. The peak bundle power for the Browns Ferry EPU is approximately 7.3 MWt versus 7.0 MWt for CLTP when averaged over the comparison cycles (see Section 2.8.3 of this SE for additional details). This represents an increase of about 4 percent compared to the corresponding total reactor power increase of 14.3 percent.

On July 31, 2014 (Reference 201), the NRC approved license amendments for the BFN Units 1, 2, and 3 to transition to AREVA ATRIUM 10XM fuel. Currently, the BFN units have a full load of AREVA ATRIUM-10 fuel (expected to be mostly ATRIUM 10XM, with some legacy ATRIUM-10 bundles at the time of EPU implementation) and TVA intends to use AREVA methodology for reload analyses in the future.

The licensee's analysis is a representative analysis performed for Unit 3 and applies to all three BFN units because all three BFN units are BWR/4 designs with Mark I containments and are either identical or have only minor differences. The most significant difference between the units is the core loadings and corresponding core designs. The impact of the differences in core designs between units and cycles is addressed in the cycle specific reload report for each unit. Minor differences between the plants and units do not impact the application of AREVA's methodology as presented in this analysis. The NRC staff's evaluation is based on the analyses for the EPU representative core. The cycle-specific EPU reload analyses when performed by the licensee and documented in the reload analysis report and core operating limits report (COLR) will confirm the results for the EPU representative core.

GEH has previously developed and implemented a number of EPUs using the NRC-approved licensing topical reports (LTRs), "Generic Guidelines for General Electric Boiling Water Reactor

Extended Power Uprate," NEDC-32424P-A, February 1999 (ELTR1) (Reference 49) and "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate," NEDC-32523P-A, February 2000 (ELTR2) (Reference 50). A letter was issued by the NRC dated June 25, 2003 (Reference 202), which provided clarifications regarding the extent to which ELTR1/2 can be used for core reloads with fuel from vendors other than GEH. The letter stated in part, that while no specific limitations were included in ELTR1/2, GEH provided analyses only to support application to its fuel type and methods. Therefore, the staff understood that these topical reports were not intended for application to core reloads with fuel from vendors other than GEH. However, the letter noted that the NRC staff has used the ELTR1/2 as general guidance for BWR EPU reviews performed to date to assure that the necessary analyses are included in the EPU applications.

Based on its EPU experience, GEH developed an approach to uprate reactor power that maintains the current plant maximum normal operating reactor dome pressure. This approach is based on the GEH Topical Report NEDC-33004P-A, Revision 4, "Constant Pressure Power Uprate (CPPU)," referred to as the CLTR (Reference 48), and the NRC staff's safety evaluation report (SER) for the CLTR dated March 31, 2003 (Reference 203). The CLTR provided appropriate guidelines for constant pressure EPU applications with a core exclusively using General Electric (GE) fuel types through GE14 and using GEH accident analysis methods. Some topics in the CLTR are directly fuel dependent because the fuel type affects the resulting evaluation of the consequences of transients and accidents. Because Browns Ferry will only contain AREVA ATRIUM-10 and ATRIUM 10XM fuel types at the time of EPU implementation in the respective BFN units, the requested Browns Ferry EPU does not reference the CLTR as the basis for areas involving fuel-dependent topics, consistent with the NRC's "Conditions and Limitations" on the use of the CLTR, as identified in the staff's CLTR SER. The fuel-dependent evaluations were performed by TVA or AREVA using NRC-approved computer codes and methods. The fuel-dependent analyses using AREVA methodologies in support of the requested EPU are contained in Attachment 8, "Fuel Uprate Safety Analysis Report (FUSAR)" to the Browns Ferry EPU LAR. For the fuel-dependent topics, the guidelines for evaluation of BWR EPUs from ELTR1 and ELTR2 were used to ensure that the necessary analyses were included in the EPU applications. In general, the licensee's plant-specific engineering evaluations supporting the power uprate were performed in accordance with guidance contained in ELTR1. This topical report was previously reviewed and endorsed by the staff. For some items, bounding analyses and evaluations provided in GEH licensing topical report ELTR2 were cited. The staff has approved ELTR2. The ELTR2 generic evaluations assume (a) a 20 percent increase in the thermal power, (b) an increase in operating dome pressure up to 1,095 psia, (c) a reactor coolant temperature increase to 556 °F, and (d) a steam and feedwater flow increase of about 24 percent. The Browns Ferry EPU specific parameters are within these limits, and hence are applicable.

The approach to achieving the EPU consists of (1) an increase in the core thermal power with a more uniform power distribution achieved by better fuel management techniques to create increased steam flow, (2) a corresponding increase in the feedwater system flow, (3) no increase in maximum core flow, and (4) reactor operation primarily along the maximum extended load line limit analysis (MELLLA) rod/flow lines. This approach is based on and is consistent with the NRC-approved boiling water reactor (BWR) EPU guidelines in ELTR1 (Reference 49), ELTR2 (Reference 50), and Attachment 39 (Reference 51) of the LAR.

An increase in the electrical output of a BWR is accomplished primarily by supplying a higher steam flow to the turbine generator. Most GE BWRs, as originally licensed, have as-designed

equipment and system capability to accommodate steam flow rates at least 5 percent above the original rating. In addition, continuing improved analytical techniques and computer codes, operating experience, and improved fuel designs have resulted in an increase in the design and operating margins, between the results of the safety analysis calculations and the licensing limits. The larger margins combined with the as-designed excess equipment, system, and component capabilities, have allowed many BWRs to increase their thermal power ratings by 5 percent (stretch uprate) without modifying any NSSS hardware and to increase power up to 20 percent (EPU) with some hardware modifications. These power increases do not significantly impact the safety systems of the plants as originally licensed.

The proposed Browns Ferry EPU will not increase the operating pressure or the current licensed maximum core flow. EPU operation will not increase reactor vessel dome pressure because the plant has made, or will make modifications to the power generation equipment, pressure controls and turbine flow capabilities to control the pressure at the turbine inlet (see Section 3.3, "Plant Modifications Supporting Extended Power Uprate," of the Enclosure to the LAR).

The scope of the NRC staff's review for the Browns Ferry EPU request included, "lessons learned" from past power uprate amendment reviews. In reviewing the licensee's request for an EPU, the staff considered the recommendations of the report of the Maine Yankee Lessons Learned Task Group (SECY-97-042, "Response to OIG Event Inquiry 96-04S Regarding Maine Yankee," February 18, 1997). The task group's main findings centered on the use and applicability of the computer codes and analytical methodologies used for power uprate evaluations. The staff requested that the licensee identify all codes and methodologies used to obtain safety limits and operating limits and explain how it verified these limits were correct for the uprate core. The licensee was also requested to identify and discuss any limitations imposed by the staff on the use of these codes and methodologies. These issues are discussed in ANP-2637NP (Reference 70).

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 emergency core cooling system (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; (3) final GDC-27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; and (4) final GDC-35, insofar as it

requires that a system to provide abundant emergency core cooling be provided to transfer heat from the reactor core following any LOCA. Specific review criteria are contained in SRP Section 4.2 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

All three BFN units will be transitioning to the AREVA ATRIUM 10XM fuel design, which is approved by the NRC in a letter dated July 31, 2014 (Reference 201), from the previous ATRIUM-10 fuel design. The initial transition began with Unit 2 Cycle 19 in the spring of 2015. Only AREVA fuel types will be resident in the Browns Ferry cores during EPU implementation. Even though all units will have transitioned to the ATRIUM 10XM fuel design prior to EPU implementation, the EPU LAR submittal is partially based on the use of evaluations utilizing the GEH/GNF GE14 fuel design. The NRC staff has reviewed AREVA reports that deal with the mechanical design for ATRIUM 10XM and ATRIUM-10 fuel, as well as the fuel rod thermal-mechanical evaluation for the BFN Units at EPU conditions.

Mechanical Design (ATRIUM 10XM)

The mechanical design report, ANP-3386NP (Reference 64), in Attachments 24 and 25 (proprietary and non-proprietary versions, respectively) of the EPU LAR, provides an evaluation of the structural design of the fuel assembly and fuel channel. The increase in core pressure drop associated with the increase in power due to the EPU affects the fuel assembly liftoff analyses and calculated stress and deformation of the fuel channel and water channel. The fuel assembly design was evaluated using the generic mechanical design criteria in ANP-89-98(P)(A) (Reference 204). The fuel channel design was evaluated using the fuel channel topical report EMF-93-177(P)(A), Revision 1, "Mechanical Design for BWR Fuel Channels," August 2005 (Reference 205). Tables 2-1 and 2-2 of the mechanical design report provide the fuel assembly component description and fuel channel and the fastener description, respectively.

The objective of designing fuel assemblies and systems is to provide assurance that:

- The fuel assembly (system) shall not fail as a result of normal operation and anticipated operational occurrences (AOOs). The fuel assembly (system) dimensions shall be designed to remain within operational tolerances, and the functional capabilities of the fuels shall be established to either meet or exceed those assumed in the safety analysis.

- Fuel assembly (system) damage shall never prevent control rod insertion when it is required.

- The number of fuel rod failures shall be conservatively estimated for postulated accidents.

- Fuel coolability shall always be maintained.

- The mechanical design of fuel assemblies shall be compatible with co-resident fuel and the reactor core internals.

- Fuel assemblies shall be designed to withstand the loads from handling and shipping.

The licensee in the mechanical design report, ANP-3386NP (Reference 64), provided a detailed fuel system evaluation of ATRIUM 10XM fuel for the BFN units to ensure the structural integrity of the design under normal operation, AOO, faulted conditions, handling operations, and shipping. The areas of evaluation consist of stress, strain, loading limits, fatigue, fretting wear, oxidation, hydriding, crud buildup, rod bow, axial irradiation growth, and assembly liftoff.

The NRC staff, in an RAI, requested the licensee to justify the use of the methodology in XN-NF-75-32(P)(A), Supplements 1 through 4 (Reference 206) for evaluation of the ATRIUM-10 and ATRIUM 10XM fuel designs for rod bow analysis. TVA responded, in its letter dated May 20, 2016 (Reference 18), that even though the base document XN-NF-75-32 was not approved because it introduced a computational model to estimate fuel rod bow which was not acceptable to the NRC staff, AREVA's Supplements to XN-NF-75-32 (Reference 206) were approved by NRC staff. This model is applied to other designs such as ATRIUM-10 and ATRIUM 10XM since the methodology is based on an empirical correlation of fuel rod gap closure versus fuel assembly average exposure. Therefore, changes in power conditions such as the EPU do not impact the rod bow predictions.

In response to an NRC staff RAI inquiring whether sufficient margin exists for ATRIUM-10 and ATRIUM 10XM at the BFN units under EPU conditions, in its letter dated May 20, 2016 (Reference 18), TVA stated that a separate power dependent minimum critical power ratio (MCPR) has been established for ATRIUM-10 and ATRIUM 10XM designs. To ensure the impact of rod bow on thermal margin is accounted for, the rod bow MCPR penalty is required for assemblies, [[

]] In the response to an NRC staff's RAI (Reference 18), [[

]]

The licensee in Table 3-1 of ANP-3386NP provided a description of each fuel system, fuel design criteria, fuel coolability information, and the results for an ATRIUM 10XM assembly. Similarly, the licensee provided, in Tables 3-2 and 3-3, the description, criteria and the results for the advanced fuel channel, and channel fastener.

The NRC staff has reviewed the mechanical design report, ANP-3386NP, for ATRIUM 10XM fuel for the BFN units at EPU conditions and determined that the licensee has evaluated the fuel and fuel channel design for the BFN units using an NRC-approved methodology. Also, the staff has determined that the fuel assembly and fuel channel meet all mechanical compatibility requirements for use in the BFN units at EPU conditions.

Mechanical Design (ATRIUM-10)

The mechanical design report for the ATRIUM-10 fuel design, ANP-3385NP (Reference 65), describes how the fuel mechanical design criteria are satisfied at Browns Ferry EPU conditions (120 percent of the OLTP). The licensee performed an ATRIUM-10 fuel assembly structural evaluation for the BFN units power increase using AREVA BWR generic mechanical design criteria, ANF-89-98(P)(A) (Reference 204). Since the increase in core power for the EPU is also associated with an increase in core pressure drop, which has an effect on some mechanical analyses such as fuel assembly liftoff, stress, and deformation of the water channel, a mechanical design evaluation was performed using the NRC-approved methodology in

XN-NF-82-06(P)(A), Revision 1 and Supplements 2, 4, and 5 (Reference 207); XN-NF-82-06(P)(A) Supplement 1 Revision 2 (Reference 208); XN-NF-85-67(P)(A), Revision 1 (Reference 209); XN-NF-85-74(P)(A) (Reference 210); and EMF-85-74(P) Revision 0 Supplement 1(P)(A) and Supplement 2(P)(A) (Reference 211). The analyses presented in this report evaluate the following maximum discharge exposures: [[ ]] assembly average exposure and 62.0 MWd/kgU rod average exposure (full-length fuel rod).

The ATRIUM-10 fuel assembly consists of a lower tie plate (LTP) and upper tie plate, 91 fuel rods, [[ ]] spacer grids, a central water channel, and miscellaneous assembly hardware. Of the 91 fuel rods, [[ ]] are part-length fuel rods. The fuel channel design was evaluated according to the criteria established in ANF-89-98(P)(A) (Reference 204) and (Reference 205).

The licensee in Table 2.1 of ANP-3385NP (Reference 65) provides the fuel assembly and component description and in Table 2.2 provides the fuel channel and the fastener description for the ATRIUM-10 fuel design. The licensee provided a summary of the fuel design evaluation which demonstrates that the design satisfies the mechanical criteria for the analyzed exposure and the linear heat generation rate (LHGR) limits under EPU conditions. These evaluations include internal hydriding; cladding collapse; overheating of cladding; overheating of fuel pellets; stress and strain limits; cladding rupture; fuel rod mechanical rupturing; and fuel densification and swelling. The fuel assembly evaluation includes stress, strain or loading limits on assembly components, fatigue, fretting wear, oxidation, hydriding, crud buildup, rod bow, axial irradiation growth, rod internal pressure, and assembly liftoff. Table 3.3 of ANP-3385NP (Reference 65) lists all the above fuel design evaluation criteria, and a description as well as the results of the evaluations. The licensee in Tables 3.4 and 3.5 of ANP-3385NP (Reference 65) lists the evaluation results for the fuel channel and channel fasteners, respectively.

Fuel coolability and the capability to insert control rods during normal operation, anticipated operational occurrences (AOOs) and accidents have been evaluated for areas such as embrittlement, violent expulsion of fuel, fuel ballooning, and structural deformations.

The NRC staff in an RAI questioned the validity of using the RODEX2A code in evaluating the fuel centerline temperature since this code does not explicitly treat fuel thermal conductivity as a function of burnup (thermal conductivity degradation (TCD)). The licensee and AREVA responded (Enclosure 1, ANP-3487P of (Reference 18)) that, based on an AREVA assessment and NRC confirmatory results, no changes to AREVA's RODEX2A code were made to implement a TCD treatment.

The NRC staff has reviewed the evaluations of the ATRIUM-10 fuel design for the BFN units at EPU conditions and determined that the evaluations demonstrated adherence to NRC-approved mechanical criteria applicable to the fuel design and meets all mechanical compatibility requirements for use in the BFN units with the co-resident fuel and the reactor core internals.

Fuel Rod Thermal Mechanical Evaluation (ATRIUM 10XM)

Fuel rod thermal-mechanical assessment analyses results for ATRIUM 10XM fuel are presented in ANP-3388NP (Reference 66). The evaluations assess fuel rod performance at EPU conditions that are assumed to first occur in Cycle 19 of BFN Unit 3 that is the second cycle using ATRIUM 10 XM fuel design. The analysis results are evaluated according to the generic fuel rod thermal and mechanical design criteria contained in ANF-89-98(P)(A), Revision 1 and Supplement 1 (Reference 204) along with design criteria provided in the RODEX4 fuel rod

thermal-mechanical topical report (Reference 212). The fuel rod analyses cover normal operating conditions and AOOs. The fuel centerline temperature analysis (overheating of fuel) and cladding strain analysis take into account slow transients at rated operating conditions.

Other fuel rod-related topics of cladding rupture, overheating of cladding, fuel rod mechanical fracturing, rod bow, axial irradiation growth, cladding embrittlement, violent expulsion of fuel and fuel ballooning are evaluated as part of the respective fuel assembly structural analysis, thermal hydraulic analyses, or LOCA analyses and are reported elsewhere.

The licensee has performed a fuel rod design evaluation for internal hydriding, cladding collapse, overheating of fuel pellets, stress and strain limits, cladding fatigue, cladding oxidation, hydriding and crud buildup, rod internal pressure and fuel handling.

These ATRIUM 10XM fuel assemblies are loaded with pellets composed of either BLEU (blended low enriched uranium) powder for the manufacture of the fuel pellets or Commercial Grade Uranium (CGU) powder. The BLEU fuel is made to a density of 95.85 percent of theoretical density instead of 96.72 percent of theoretical density for standard ATRIUM 10XM fuel pellets. The NRC staff has previously reviewed the licensee's use of BLEU fuel regarding the TVA LAR for the ATRIUM 10XM transition, ANP-3248P (Reference 213). The differences/similarities between the commercial grade uranium (CGU) and BLEU fuel have been discussed in ANP-3248P (Reference 213). The summary of the discussion highlights are: (1) both CGU and BLEU are subject to the same maximum U^{235} enrichment of 4.95 percent, (2) there is no difference chemically, (3) thermal conductivity and mechanical properties are not impacted, (4) the primary difference is that BLEU has a higher concentration of U^{234} and U^{236} isotopes, (5) the decrease in reactivity due to the increase in U^{236} is similar to addition of Gadolinia in the fuel, and (6) the isotopic concentration of U^{234} and U^{236} are explicitly included in the CASMO-4/MICROBURN-B2 neutronic design and licensing process.

Listed below are the highlights of key fuel design parameters.

Overheating of Fuel Pellets

Fuel failure from the overheating of the fuel pellets is not allowed. The melting point of the fuel includes adjustments for gadolinia content. The LHGR limit is adjusted to protect against fuel centerline melting during steady-state operation and during AOOs. Fuel centerline temperature is evaluated using the RODEX4 code for both normal operating conditions and AOOs. The fuel rod model in RODEX4 considers the fuel column, gap region, cladding, gas plenum, the fill gas, and released fission gases. The operational conditions are controlled by the input of [[

]]. The heat conduction in the fuel and clad is modelled with all the thermally activated processes such as [[

]]. Rod power histories are generated that include [[
]]. Since RODEX4 is a best-estimate code, uncertainties are taken into account by a statistical method. These uncertainties include, power measurement and operational uncertainties [[
]], manufacturing uncertainties [[
]], and model uncertainties [[

]]. TVA, in Table 3-2 and Table 3-3 of ANP-3388NP (Reference 66), lists the results for equilibrium and cycle-specific conditions, respectively.

The NRC staff has reviewed the results from the RODEX4 analysis for the equilibrium cycle and Cycle 19 operation. The NRC staff has determined that sufficient margins exist for fuel centerline temperature, maximum transient induced cladding tangential strain, and maximum rod internal pressure for steady state, control rod withdrawal error and flow runup for both equilibrium and Cycle 19 operation. Also, the staff reviewed the results for equilibrium and Cycle 19 operation for maximum cladding oxidation, cumulative usage factor and axial column gap formation, and determined that there is sufficient margin to the limit for the same.

Oxidation, Hydriding, and Crud Buildup

The corrosion model in RODEX4 includes an enhancement factor that is derived from poolside measurement data to obtain a fit of the expected oxide thickness. RODEX4 has provisions to account for the heat transfer coefficient of crud, and thereby the analysis implicitly accounts for the thermal effect of normal, low levels of crud. Abnormal levels of crud require a specific analysis to address the higher crud level. The maximum oxide on the fuel rod cladding has been fixed at a limit not to exceed an approved value in RODEX4, which was reduced when RODEX4 was first implemented by the licensee, ANP-3388NP (Reference 66). The oxide limit is evaluated such that it is greater than 99.9 percent probability and 95 percent confidence level.

The NRC staff has reviewed the licensing analyses for ATRIUM 10XM for each of the design criteria at the EPU conditions for a maximum fuel rod discharge exposure of 62 GWd/MTU and determined that the design criteria are satisfied when the fuel is operated at or below the LHGR limit.

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, GDC-27, and GDC-35 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the fuel system design.

2.8.2 Nuclear Design

Regulatory Evaluation

The NRC staff reviewed the nuclear design of the fuel assemblies, control systems, and reactor core to ensure that fuel design limits will not be exceeded during normal operation and AOOs, and that the effects of postulated reactivity accidents will not cause significant damage to the RCPB or impair the capability to cool the core. The NRC staff's review covered core power distribution, reactivity coefficients, reactivity control requirements and control provisions, control rod patterns and reactivity worths, criticality, burnup, and vessel irradiation. The NRC's acceptance criteria are based on (1) 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) draft GDC-7, insofar as it requires that the core design shall ensure that power oscillations which could cause damage in excess of acceptable fuel damage limits are not possible or can be readily suppressed; (4) draft GDC-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 GDC-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 GDC-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 GDC-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; (9) final GDC-27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; and (9) 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

BFN Unit 3 Cycle 19 EPU Fuel Cycle Design

The licensee performed nuclear fuel cycle design analyses for the BFN Unit 3 Cycle 19 with ATRIUM 10XM fuel at EPU (120 percent OLTP) conditions. These analyses have been performed with the approved AREVA neutronics methodology in EMF-2158(P)(A)

(Reference 214), which consists of the CASMO-4 lattice depletion code to generate cross sections and local power peaking factors. The methodology also consists of MICROBURN-B2, a three dimensional core simulator code which utilizes the pin power reconstruction model to determine the thermal margins presented in this report. The ACE critical power correlation in ANP-10298PA (Reference 215) and ANP-3140 (Reference 216) was utilized for the ATRIUM 10XM assemblies in the core. The Siemens Power Corporation B (SPCB) critical power correlation in EMF-2209(P)(A) (Reference 217) is used for the ATRIUM-10 assemblies in the core. Figures 3.1 through 3.5, along with Table 3.1 of ANP-3372NP (Reference 61) show the reference loading pattern used in the fuel cycle design. The specific core location of the fresh assemblies in Cycle 19 is provided in Appendix C of ANP-3372NP (Reference 61). The cycle design calculations demonstrate adequate hot excess reactivity, SLC shutdown margin, and cold shutdown margin throughout the cycle. The shutdown margin is in conformance with the TS value.

The staff reviewed the Cycle 19 fuel cycle design that consists of a core loading pattern, design depletions, control rod patterns, hot excess reactivity and cold shutdown margin. The staff has verified that the cycle design calculations have demonstrated adequate hot excess reactivity and cold shutdown margin throughout the cycle.

Browns Ferry EPU Equilibrium Fuel Cycle Design

The licensee performed an equilibrium fuel cycle design analysis and fuel management calculations (see ANP-3342NP (Reference 60)) for the Browns Ferry BWRs with ATRIUM 10XM fuel at EPU (120 percent OLTP) conditions using the AREVA neutronics methodology (EMF-2158(P)(A) (Reference 214)) that consists of CASMO-4 lattice depletion code to generate cross sections and the MICROBURN-B2 code for pin power reconstruction to determine thermal margins.

The equilibrium cycle fresh batch size (332 ATRIUM 10XM assemblies) and batch average enrichment **[[** **]]** were determined to meet the energy requirements provided by the licensee. The equilibrium cycle assumes the use of BLEU material for one fuel type to account for about 30 percent of the fresh reload assemblies. The licensee in ANP-3342NP (Reference 60) provides information on fresh reload fuel axial enrichment, gadolinia distributions, control rod patterns, acceptable power peaking and the associated margins to limits for projected equilibrium cycle operation. The licensee in Table 2.1 of ANP-3342 (Reference 60) lists the Browns Ferry equilibrium cycle energy and key results from the equilibrium fuel cycle design analysis. The results include values for cycle energy requirements and exposures, reactivity margins, thermal limit margins (LHGR, MAPLHGR), and critical power ratio (CPR). Reactivity margins provided include the beginning of cycle (BOC), minimum cold shutdown margin (including the moderator temperature), SLC, and shutdown margin. Hot excess reactivity used is provided for normal, short, and long cycle end of cycle (EOC) depletions. The licensee also provided detailed results of control rod patterns, core average axial power and exposure distributions, and fresh fuel enrichments for both CGU and BLEU fuel designs for the equilibrium cycle.

The NRC staff reviewed the Browns Ferry equilibrium fuel cycle design that consists of a core loading pattern, design depletions, control rod patterns, hot excess reactivity and cold shutdown margin. The staff has verified that the cycle design calculations have demonstrated adequate hot excess reactivity and cold shutdown margin throughout the cycle.

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 GDC-10 and 27, and draft GDC-7, 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 review also covered hydraulic loads on the core and RCS components during normal operation and design basis accident (DBA) conditions and core thermal-hydraulic stability under normal operation and anticipated transients without scram (ATWS) events. The NRC's acceptance criteria are based on (1) 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) draft GDC-7, insofar as it requires that the core design shall ensure that power oscillations that could cause damage in excess of acceptable fuel damage limits are not possible or can be readily suppressed. Specific review criteria are contained in SRP Section 4.4 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

Thermal hydraulic analyses are performed to verify that design criteria are satisfied and to establish thermal operating limits with acceptable margins of safety during normal reactor normal operation and AOOs (see ANP-3327NP (Reference 67) and ANF-89-98(P)(A) (Reference 204)). These analyses demonstrated compliance with the thermal hydraulic design criteria such as, hydraulic compatibility, thermal margin performance, fuel centerline temperature, rod bow, stability, LOCA analysis, control rod drop analysis, and seismic/LOCA liftoff. This section describes the thermal-hydraulic analyses performed for the BFN units at EPU conditions.

Hydraulic Characterization

A characterization analysis for the ATRIUM 10XM and ATRIUM-10 fuel design verifies that the basic geometric parameters of the two fuel designs are compatible with the core internal

characteristics such as the grid loss coefficients; orifice and LTP loss coefficient; the combined LTP flow holes and LTP/fuel support interface resistance; and the LTP-channel seal resistance. The licensee in Table 3.3 of ANP-3327NP (Reference 67) lists the loss coefficients [[

]]. The flow tests and pressure loss tests to confirm the hydraulic characterization of the fuel are done using AREVA's portable hydraulic test facility. The staff verified the results from the hydraulic characterization analysis and determined that the fuel designs are compatible with the fuel support and the LTP.

Hydraulic Compatibility

A hydraulic compatibility analysis is intended to show that the hydraulic flow resistance of the reload fuel assemblies is sufficiently similar to the existing fuel in the reactor such that there is no significant impact on total core flow or the flow distribution among assemblies in the core. The thermal-hydraulic analyses are performed using the NRC-approved methodology in XN-NF-80-19(P)(A) (Reference 218). Pressure drop calculations are performed using the XCOBRA code. The relative performance of ATRIUM-10 and ATRIUM 10XM is evaluated as a mixed core analysis for EPU conditions at the BFN units. This analysis demonstrates that the thermal-hydraulic design criteria are satisfied for the Browns Ferry core configuration under EPU conditions. The hydraulic compatibility analysis models each of the fuel assembly channels that are grouped into equivalent hydraulic channels such that the pressure drop across the channels is the same.

The input to the hydraulic compatibility analysis is for the two state points; 100 percent EPU power/100 percent flow and 54.3 percent EPU power/37.3 percent flow. Evaluations were made with the bottom-, middle-, and top-peaked axial power distributions. Results presented in Tables 3.5 through 3.8 and Figures 3.2 and 3.5 of ANP-3327NP (Reference 67) are for bottom peaked power distribution. Results for the middle-peaked and top-peaked axial power distributions show similar trends.

Two different core loadings were evaluated for the compatibility analysis, core loading 1 consists of approximately one third ATRIUM 10XM fuel with the remainder ATRIUM-10 fuel. The core average results and the differences between the fuel designs for both rated and off-rated state points are within the range considered hydraulically compatible, that is, the results indicate that [[

]]. Based on the reported changes in pressure drop and assembly flow caused by the first reload of ATRIUM 10XM fuel, the ATRIUM 10XM design is considered hydraulically compatible with the ATRIUM-10 design for EPU operation since the thermal-hydraulic design criteria are satisfied.

The second core loading for the compatibility analysis consists of approximately two thirds ATRIUM 10XM fuel with the remainder being ATRIUM-10 fuel. The results indicate that for [[

]].

Based on the reported changes in pressure drop and assembly flow caused by the second reload of ATRIUM 10XM fuel at Browns Ferry, the ATRIUM 10XM design is considered hydraulically compatible with the ATRIUM-10 fuel design for EPU operation since the thermal-hydraulic design criteria are satisfied.

The NRC staff has reviewed the thermal-hydraulic compatibility analysis results for the ATRIUM 10XM and ATRIUM-10 fuel designs and determined that these fuel designs are hydraulically compatible at BFN units for the entire range of licensed power-to-flow operating map.

Thermal Margin Performance

Relative thermal margin analyses were performed in accordance with the thermal-hydraulic methodology for AREVA's XCOBRA-T code (Reference 219). Critical power ratio (CPR) values for ATRIUM 10XM fuel are calculated with the ACE/ATRIUM 10XM critical power correlation while the CPR values for ATRIUM-10 fuel are calculated with the SPCB critical power correlation. The staff reviewed the methodology and the results of the thermal margin performance analysis and determined that ATRIUM 10XM fuel will not adversely affect the thermal margin performance of the ATRIUM 10 fuel.

Transient Analysis

As stated earlier, the constant pressure power uprate will increase the operating power by 14.3 percent. In response to an NRC staff RAI, the licensee stated in its letter dated April 4, 2016 (Reference 11), that the peak bundle power will increase to approximately 7.3 MWt for the EPU as compared to 7.0 MWt for CLTP when averaged over the comparison cycles. This represents an increase of peak bundle power by about 4 percent as opposed to the corresponding total reactor power increase of 14.3 percent.

The licensee provided an integral transient uncertainty evaluation in Section 8 of ANP-2860P, Supplement 2 (see (Reference 69) for the non-proprietary version of this document) in the form of benchmarks against simulated transients in the KATHY facility with ATRIUM-10XM fuel geometry. Figure 8-1 of ANP-2860P (Reference 69), as shown below, presents a summary of the predicted times to dryout versus KATHY measurements for two simulated transients: Load rejection no bypass (LRNB) and pump trip transient initiated at [[

]]. These experimental transient uncertainty evaluations provide an integral test of the complete AREVA methodology, including void fraction/quality, pressure drop, heat transfer, and reactivity feedbacks. AREVA methodology consistently predicts shorter (conservative) dryout times than measured. Based on these data, the NRC staff concludes that these integral transient evaluations provide confirmation that the AREVA transient methodology is applicable to ATRIUM 10XM, and hence acceptable.

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Time to dryout from typical hydraulic benchmarks of AREVA methods versus KATHY transient simulations (Figure 8-1 of ANP-2860P, Supplement 2)

Thermal-Hydraulic Stability

TVA will continue to implement the Option III stability solution that has been reviewed and approved by the NRC (see NEDO-32465-A (Reference 220)). The Option III parameters and setpoints are calculated using the approved MICROBURN-B2, EMF-2158(P)(A) (Reference 214), and DIVOM, BAW-10255PA (Reference 221) methodologies. No exceptions to the approved methodology were made. Option III setpoints and operating limit minimum critical power ratio (OLMCPR) requirements vary from cycle to cycle, and will be affected by EPU operation, but the approved methodology automatically adjusts the results based on the calculated cycle-specific power distributions.

Option III is a detect-and-suppress stability solution that continuously monitors the oscillation power range monitor (OPRM) system. The solution uses the period based detection algorithm as the licensing bases algorithm to provide SLMCPR protection if unstable power oscillations develop. Option III is implemented in most U.S. BWRs, including those at EPU conditions. Option III is already implemented in Browns Ferry, and it is applicable under EPU conditions without any changes to the methodology.

Option III relies on a scram setpoint that is calculated using the delta-over-initial-oscillation magnitude (DIVOM) methodology. The DIVOM slope is calculated on a cycle-specific basis using the approved methodology in RAMONA5-FA Code, BAW-10255PA (Reference 221). Typical applications for Browns Ferry use the more conservative generic DIVOM slope value of 0.45, and the cycle-specific calculation is used only to confirm that the generic value is conservative. However, the calculated DIVOM value will be used if the generic slope is not conservative for a specific-cycle.

As part of the cycle-specific DIVOM calculation, AREVA's methodology for Browns Ferry calculates the CPR response versus the hot channel oscillation magnitude (HCOM) using the approved AREVA DIVOM methodology BAW-10255PA (Reference 221). The DIVOM methodology explicitly takes into account the cycle-specific power distribution changes that may occur when implementing the EPU.

When Option III is declared inoperable, backup stability protection (BSP) regions enter into effect. BSP regions are calculated on a cycle-specific basis using the STAIF methodology (Reference 222), which is the approved frequency domain stability code used for BSP region calculations. Two sets of BSP regions apply depending on the feedwater temperature (nominal and reduced feedwater temperature). The BSP regions are calculated on a cycle-specific basis and, thus, the AREVA methodology explicitly accounts for power distribution changes that may occur when implementing the EPU. Browns Ferry intends to implement generic conservative BSP regions that do not change cycle to cycle. The STAIF BSP calculations are used to confirm that the generic BSP regions are applicable. However, these regions will be expanded if required for a specific cycle.

The Browns Ferry OPRM trip-enabled region will be rescaled from 25 percent power to 23 percent power to maintain the same absolute power in MW, which is acceptable.

Option III (Reference 220), STAIF (Reference 222), and RAMONA5-FA (Reference 221) have been generically approved for use up to EPU conditions, and their use is thus acceptable.

In Section 2 of ANP-2860, Revision 2 (Reference 223), the licensee states that the flatter radial power profile expected under EPU conditions would tend to favor the out-of-phase (OOP) instability mode over the core-wide mode, which was the dominant mode in Browns Ferry pre-EPU. Even though, left unprotected, the OOP instability mode has inherently more impact on fuel performance because larger flow oscillations may result, Option III was specifically designed to protect against both the core wide and OOP modes. Therefore, Option III provides a scram to ensure fuel limits are not violated in Browns Ferry for either of the two instability modes.

ATWS with Instability

The EPU does not impact significantly the progression of ATWS with instabilities (ATWSI) because the increase in power is achieved along a constant flow-control line. The first step in ATWS is to trip the recirculation pumps, and the reactor reaches the same point under the EPU as under pre-EPU operation.

For maximum extended load line limit analysis plus (MELLLA+) applications, the NRC requires plant-specific evaluations of ATWSI, but does not require this for an EPU. Therefore, TVA did not specifically perform ATWSI calculations. Instead, TVA provided justification why operation under EPU conditions does not impact the previous ATWSI conclusions, which are based on BWROG-sponsored generic ATWSI calculations in NEDO-32047-A (Reference 224) and NEDO-32164 (Reference 225). This BWROG evaluation resulted in the ATWSI mitigation actions, which require prompt water level reduction below the feedwater spargers and early boron injection. The mitigation actions have been implemented in Browns Ferry emergency operating procedures (EOPs). In response to an NRC staff RAI regarding the information presented in Table 1.1 of FUSAR (Reference 226), the licensee, in its letter dated April 4, 2016

(Reference 11), confirmed that Revision 3 of the BWROG emergency procedures guidelines (EPGs) have been implemented.

Based on the above, the NRC staff concurs that plant-specific ATWSI evaluations are only required for extended flow domain applications (like MELLLA+ or extended flow window).

Bypass Voiding

Flow in the bypass region is a function primarily of the core pressure drop. At high powers and flows, the bundle pressure drop is large enough to compensate for the elevation pressure drop in the bypass, and bypass flow is primarily controlled by the friction losses in the orifice. At lower flow, however, the bundle pressure drop is smaller, and is of the same order of magnitude as the bypass elevation pressure drop with void fraction near zero. As the bypass flow is reduced, some degree of bypass boiling may occur, which impacts primarily the calibration of local power range monitor (LPRM) detectors by affecting the neutron flux in the bypass region. The MICROBURN-B2 core simulator has [[ ]] and, thus, provides a conservative estimate of bypass voids.

The licensee evaluated the degree of bypass boiling in Browns Ferry under EPU conditions at multiple exposures in Section 7.3 of ANP-2860P, Supplement 2 (Reference 69) and concluded that no significant bypass boiling is anticipated. The licensee, in Figures 7-5, 7-6, and 7-7 of ANP-2860P, Supplement 2, provided a summary of the void fractions calculated in the bypass region for a Browns Ferry equilibrium cycle. Figure 7-7 shows that the bypass voids at LPRM detector D elevation are [[ ]] and well within the acceptance criterion of 5 percent for Option III. In addition, Section 2 of ANP-2860, Revision 2 provides a study of the impact of bypass voiding on LPRM detector calibration using CASMO4 lattice calculations and very conservative void assumptions, which demonstrate minimal impact to the normalized OPRM response that is the measured variable of interest for the Option III stability solution. Based on these results, TVA concluded that it had accounted for the possible presence of bypass voids and concluded that the LPRM instrument degradation is minimal. Based on the above, the NRC staff concurs with this evaluation.

Hydraulic Loading

Operation with ATRIUM-10 and ATRIUM 10XM fuels was evaluated (Section 2.2.3.2.1 of the PUSAR (Reference 47) and Section 2.8.3.3 of the FUSAR (Reference 164)) by TVA to determine the impact on pressure drop differences across reactor internal components. The evaluation shows AREVA fuel designs are either bounded, or essentially the same as, the GE 13 fuel design, which has been the basis of Browns Ferry reactor internal pressure differential analyses, and are, therefore, acceptable.

MICROBURN-B2 Issues at Low Flow

Two issues were identified in MICROBURN-B2 that potentially impact the calculations provided for the Browns Ferry EPU LAR:

1. Potential hydraulic non-convergence in MICROBURN-B2 at low flow conditions.
2. Behavior of the MICROBURN-B2 void quality correlation for low flow conditions

The licensee addressed both issues in AREVA's documents FS1-0024528 (Reference 227) and FS1-0024827 (Reference 226), and found them to have no significant relevance. The NRC staff performed a review of the licensee's evaluation and found that additional information was needed, as discussed below.

MICROBURN-B2 Non-Convergence Issue

For flows less than 40 percent, MICROBURN-B2 may fail to converge the bypass-area flow, and it oscillates between two solutions: one with and one without significant bypass voids. Which of the two solutions is used appears to be random, and it depends on when MICROBURN-B2 stops on the maximum number of iterations. The error affects primarily the axial power shape because of the effect of bypass voids on the neutronic solution.

The non-convergence issue affects primarily stability-related calculations (DIVOM, backup stability protection (BSP), and OPRM setpoint analyses), but it also could potentially have affected the flow runback analyses and the low power/flow ARTS control rod withdrawal error. A review of the calculations for the Browns Ferry EPU LAR indicated that only the stability-related calculations were affected.

AREVA resolved the issue and implemented corrections in MICROBURN-B2 with the release of UNOV10 (a new version of MICROBURN-B2). The primary patch produces a print out to the error file, which the user is required to review by procedure, when non-convergence issues are detected.

Impact on DIVOM

The DIVOM calculations were performed with a corrected version of MICROBURN-B2 and the resulting DIVOM curves are shown in Figure 1 of FS1-0024528 (Reference 227). Minimal differences are observed (red versus blue points.) In addition, Browns Ferry uses the generic BWROG DIVOM slope, which is significantly more conservative than either calculation.

Based on its review of the information presented by TVA and AREVA, the NRC staff concurs that the impact of the MICROBURN-B2 bypass flow non-convergence on the DIVOM slope is minimal, and it has no impact on the generic DIVOM slope used.

Impact on BSP

The licensee has presented the information concerning the impacts on the calculated decay ratios that are used to define the BSP regions. The results are presented in Tables 1 and 2 of FS1-0024528 (Reference 227). The differences are minimal (less than 5 percent) and do not affect the BSP region documented in the Core Operating Limits Report (COLR). The cycle-dependent decay ratio calculations are only used to confirm that the BSP regions remain conservative; thus, the BSP regions have not changed as a result of this MICROBURN-B2 issue.

Based on the information presented by Browns Ferry and AREVA, the NRC staff concurs that the impact of the MICROBURN-B2 bypass flow non-convergence on the decay ratio values calculated at Browns Ferry is minimal and has no impact on the COLR BSP regions.

Impact on OPRM Setpoint Settings

The OLMCPR values required to maintain SAFDLs for a two recirculation pump trip (2RPT) followed by instability and an OPRM scram have been recalculated and are shown in Tables 3 and 4 of FS1-0024528 (Reference 227) for both the equilibrium and the first representative cycles. For both cycles, the required OLMCPR has decreased significantly. In response to an NRC staff RAI, the licensee explained, in its letter dated April 4, 2016 (Reference 11), that the corrected low-flow convergence issue had a significant impact on the final power calculated by MICROBURN-B2 after the 2RPT, and this change in power propagates to the CPR calculation, which is the basis for the setpoint calculation. The final natural circulation power after the 2RPT is approximately 8 percent lower when the converged MICROBURN-B2 calculations are used, and this translates to an increase in CPR of approximately 8 percent and the observed changes in setpoints. In the RAI response, the licensee also states that the other two components of the OPRM setpoint (namely HCOM and DIVOM) do not change significantly and are not affected by the MICROBURN-B2 non-convergence issue.

MICROBURN-B2 Void-Quality Correlation Issue

The void-quality correlation used in MICROBURN-B2 implements a **[[** **]]**. Unrealistic results have been identified when the correlation is applied to low flow, high quality conditions, which are not part of normal reactor operation, but may occur during extreme conditions such as in ATWSI evaluations.

TVA determined that the correlation behaves appropriately if the following range of conditions is maintained **[[** **]]**. These operating restrictions are implemented in release UNOV10 of MICROBURN-B2. The NRC staff RAI requested the licensee provide a more detailed explanation of the analysis performed, including the cause and effect of the changes implemented in the correlation for this analysis. In its response dated April 4, 2016 (Reference 11), the licensee stated that implementing the **[[** **]]** did have an effect on peripheral and bypass channels, but not on the hot and limiting channels. Therefore, the NRC staff finds that the results of the original calculations are applicable.

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 [equivalent to or a justified extrapolation from] proven designs, (3) provides acceptable margins of safety from conditions that would lead to fuel damage during normal reactor operation and AOOs, and (4) is not susceptible to thermal-hydraulic instability. The NRC staff further concludes that the licensee has adequately accounted for the effects of the proposed EPU on the hydraulic loads on the core and RCS components. Based on this, the NRC staff concludes that the thermal and hydraulic design will continue to meet the requirements of final GDC-10 and draft GDC-7 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to thermal and hydraulic design.

2.8.4 Emergency Systems

2.8.4.1 Functional Design of Control Rod Drive System

Regulatory Evaluation

The NRC staff's review covered the functional performance of the control rod drive system (CRDS) to confirm that the system can effect a safe shutdown, respond within acceptable limits during AOOs, and prevent or mitigate the consequences of postulated accidents. The review also covered the CRDS cooling system to ensure that it will continue to meet its design requirements. The NRC's acceptance criteria are based on (1) 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-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 that could result in exceeding acceptable fuel damage limits; (4) draft GDC-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 GDC-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

In the updated PUSAR (Reference 37), TVA evaluated the impacts of the EPU on control drive performance. TVA evaluated the following elements of the control drive performance:

1. Scram Time Response
2. Control Rod Drive Positioning and Cooling, which includes:

    a. Control Rod Drive Positioning
    b. Control Rod Drive Cooling, and
    c. Control Rod Drive Integrity Assessment

The EPU does not change the reactor dome operating pressure, and only produces **[[**

]] because of the increased steam flow and associated pressure drop in the vessel. Therefore, TVA concluded that EPU impacts on control drive performance are minimal. Based on its review of the submitted information, the staff found this conclusion acceptable.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the functional design of the CRDS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system and demonstrated that the system's ability to effect a safe shutdown, respond within acceptable limits, and prevent or mitigate the consequences of postulated accidents will be maintained following the implementation of the proposed EPU. The NRC staff further concludes that the licensee has demonstrated that sufficient cooling exists to ensure that compliance with the system's design bases will continue to be maintained following 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 GDC-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 CRDS.

2.8.4.2 Overpressure Protection during Power Operation

Regulatory Evaluation

Overpressure protection for the RCPB during power operation is provided by relief and safety valves and the reactor protection system. The NRC staff's review covered relief and safety valves on the main steam lines 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) draft GDC-33, 34, and 35, insofar as they require 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

The EPU does not change the reactor dome operating pressure, but it increases the steam flow by about 14 percent compared to CLTP, which increases the possibility of vibrations and increased pressurization during some transient events. The constant pressure power uprate, NEDC-33004P-A (Reference 48) specifies that these events must be evaluated on a plant-specific basis.

COTRANSA2, which is a computer program for boiling water reactor transient analyses (see ANF-913(P)(A) (Reference 228)) analyses have been performed with an equilibrium ATRIUM 10XM core, and the results indicate that the MSIV closure with scram on high flux (i.e., not crediting the MSIV or turbine stop valve position scram) is the limiting event. The calculated peak pressure is 1349 psig, which is below the 1375 psig ASME limit even assuming one SRV out of service. The conclusions are confirmed on a cycle-specific basis for the ASME overpressure evaluation for each reload.

For Browns Ferry, no safety/relief valve (SRV) setpoint increase is needed because there is no change in the dome pressure or simmer margin. Therefore, there is no effect on valve functionality (opening/closing).

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the overpressure protection capability of the plant during 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 draft GDC-9, 33, 34, and 35 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. 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-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 (4) 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

TVA performed, in Section 2.8.4.3 of the PUSAR (Reference 47), plant-specific analyses that demonstrated that the RCIC system is capable of maintaining the water level outside the shroud above the Level 1 setpoint to prevent ADS actuation following a limiting loss of feedwater (LOFW) event at EPU conditions. Thus, the RCIC injection rate is adequate to meet the requirements for inventory makeup.

As stated in the CLTR (NEDC-33004P-A) (Reference 48) the EPU does not affect the net positive suction head (NPSH) for the RCIC system because it does not affect the pressure in the condensate storage tank, which is the primary normal source of water for the RCIC. The staff concurs with this evaluation.

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 a station blackout event and the ability of the system to provide makeup to

the core following a small break in the RCPB. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on these events and demonstrated that the RCIC system will continue to provide sufficient 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 GDC-4, 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 provide decay heat removal following shutdown. The RHR system is typically a low pressure system that takes over the shutdown cooling function when the RCS temperature is reduced. The NRC staff's review covered the effect of the proposed EPU on the functional capability of the RHR system following shutdown to provide decay heat removal. 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 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 in Browns Ferry can operate in the following modes:

1. Low Pressure Coolant Injection (LPCI) Mode
2. Suppression Pool and Containment Spray Cooling Modes
3. Shutdown Cooling Mode
4. Fuel Pool Cooling Assist
5. Standby Cooling Mode

TVA provided plant-specific evaluations for all the above modes, except the LPCI mode, which was disposed generically in the CLTR (NEDC-33004P-A (Reference 48)) because there are no changes in reactor pressure when the LPCI system is required for RHR. The EPU does affect decay heat levels; thus, plant-specific evaluations were performed to evaluate the RHR performance during the remaining modes of operation. The evaluations concluded that the acceptance criteria can be met by the current RHR system without any modifications for EPU operation. The NRC staff found this conclusion acceptable.

Because of higher decay heat at EPU conditions, the shutdown cooling (SDC) analysis for the EPU determined that the time needed for cooling the reactor to 125 °F during a normal reactor shutdown, with two RHR pumps and associated heat exchangers in service, is increased to approximately 34 hours from approximately 24 hours at CLTP conditions. The increase in the normal reactor shutdown time for the EPU indicates that a normal reactor shutdown may take longer. This has no effect on plant safety or the design operating margins; no changes to the RHR system are required and the BFN units during the SDC mode of operation are consistent with the CLTR (NEDC-33004P-A (Reference 48)).

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 EPU effects 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 GDC-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 system (SLCS) provides backup a capability for reactivity control independent of the control rod system. The SLCS injects a boron solution into the reactor to effect shutdown. The NRC staff reviewed 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 GDC-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 GDC-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; (3) 10 CFR 50.62(c)(4), insofar as it requires that the SLCS be capable of reliably injecting a borated water solution into the 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 is provided in Matrix 8 of RS-001.

Technical Evaluation

This section of the SE pertains to the NRC staff's evaluation of the SLCS's ability to provide reactivity control independent of the control rods. Refer to Section 2.1.8.1 regarding the SLCS's ability to control suppression pool pH following a LOCA.

The SLCS is designed to shut down the reactor from rated power conditions to cold shutdown if some or all of the control rods cannot be inserted. This manually operated system pumps a highly enriched sodium pentaborate solution into the vessel to provide neutron absorption and achieve a subcritical reactor condition.

The licensee will increase the B-10 enrichment from 63.1 percent to 94 percent to improve the ATWS performance. This modification increases the SLCS shutdown margin and reduces the integrated heat to containment, which significantly improves ATWS performance.

The licensee provided in the LAR (Reference 1) a plant-specific analysis to confirm that Browns Ferry satisfies all ATWS acceptance criteria under EPU operating conditions. In addition, the licensee performed an evaluation to ensure that the SLCS pumps have sufficient discharge pressure during all events and that the SLCS relief valve setpoint prevents it from lifting during operation.

The CLTR (NEDC-33004P-A (Reference 48)) states that operation at the higher EPU power levels does not affect the ultimate shutdown capability of the SLCS because the EPU upgrade maintains a constant maximum operating core-average void fraction. The SLCS cold shutdown margin calculations are run on a cycle-specific basis using the 720 ppm values for natural boron equivalent. The resulting SLCS shutdown margin results are compared to the SLCS shutdown margin acceptance criteria. These calculations will continue to be performed for all future cycles. TVA's goal is to utilize these cycle-specific SLCS shutdown margin results to validate that 720 ppm boron concentration assumption remains conservative, so that emergency operating procedures (EOPs) do not need to be changed cycle-to-cycle.

In the past, BFN Unit 1 used a conservative cold shutdown boron concentration value of 720 ppm, while BFN Units 2 and 3 used a more aggressive concentration value of 660 ppm, which needed to be confirmed on a cycle-specific basis. Since Browns Ferry has increased the B-10 concentration, which significantly reduces the boron injection time, TVA decided to use the same 720 ppm value for all three units to simplify operator training and engineering design.

The maximum SLCS pump discharge pressure is 1295 psig, and the SLCS relief valve setpoint is nominally 1425 psig (which is tested periodically and expected to be significantly higher). Nevertheless, the possibility exists that given early SLCS initiation, the reactor pressure will not have time to recover from a hypothetical early pressurization (e.g., turbine trip). TVA evaluated the maximum amount of borated SLC discharge that would be lost if the SLCS relief valve were to open because of an early SLCS actuation. The evaluation confirms that the amount of B-10 lost in this case would not be significant and would not affect the capability to achieve cold shutdown.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the SLCS and concludes that the licensee has adequately accounted for the EPU effects on the system and demonstrated that the system will continue to provide reactivity control independent of the control rod system. Based on this, the NRC staff concludes that the SLCS will continue to meet the requirements of draft GDC-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 SLCS.

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 as well as 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 GDC-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 it requires that a reactivity control system be provided capable of preventing the exceedance of 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

Related to this topic, the following transients were evaluated by TVA for Browns Ferry under EPU conditions using approved methods (refer to ANP 3403P, "Fuel Uprate Safety Analysis Report for Browns Ferry Units 1, 2, and 3" (FUSAR), Revision 2 (Reference 164)):

1. Loss of feedwater heater (LFWH)
2. Feedwater controller failure (FWCF)
3. Pressure regulator failure open (PRFO)
4. Inadvertent opening of an MSRV (IORV)

The SLMCPR limit is a SAFDL and is established such that at least 99.9 percent of the fuel rods in the core would not be expected to experience the onset of transition boiling as a result of normal operation and transients, which in turn ensures fuel cladding damage does not occur. The SLMCPR limit is established such that fuel design limits are not exceeded during steady state operation, normal operational transients, and abnormal operational transients. As such, fuel damage is calculated not to occur if the limit is not violated. The SLMCPR is calculated for each reload cycle to verify that the TS value for SLMCPR is applicable to each reload cycle. Because fuel damage is not directly observable, a step-back approach is used to establish corresponding operating limits. The Operating Limit Minimum Critical Power Ratio (OLMCPR) is established by summing the cycle-specific core reload transient analyses adders (ΔCPR) and the TS SLMCPR value. Establishment of the OLMCPR provides a margin to ensure that the specific SAFDL (in this case the SLMCPR) is not violated by the limiting transient. The remaining transients are evaluated to confirm they are bounded by the limiting transient and therefore require no further consideration.

The NRC approved ELTR1 (Reference 49) for generic evaluation of BWR EPUs. Table E-1 of ELTR1 provides a list of transients that should be addressed in the BWR power uprate applications. The transient with the largest ΔCPR at EPU power level becomes the limiting transient from the standpoint of SLMCPR. The rest of the transients identified in Table E-1 are analyzed to confirm that their ΔCPR values are bounded by the limiting transient. The licensee in Table 2.8 5 of FUSAR, as shown below, demonstrated that the limiting event is FWCF. For the FWCF event initiated at 87.5 percent power, the ΔCPR is 0.39 in an off rated power case. The rated power case for the FWCF event results in a ΔCPR of 0.34. OLMCPRs for rated and off rated powers will be established each reload by analyzing the FWCF event at various powers and establishing power dependent MCPR values.

Transient Analyses Results

AOO Event	ΔCPR	$LHGRFAC_P$
FWCF		
100% Power	0.34	1.00
87.5% Power	0.39	1.00
LRNB		
100% Power	0.31	1.00
87.5% Power	0.32	1.00
TTNB		
100% Power	0.31	1.00
87.5% Power	0.31	1.00
MSIV Closure (All)		
100% Power	0.16	1.00
87.5% Power	0.15	1.00
MSIV Closure (Single)		
100% Power	0.11	1.00
87.5% Power	0.09	1.00
IHPS		
100% Power	0.13	1.00
87.5% Power	0.16	1.00
Fast Recirculation Runup		
66% P/52% F	0.13	1.00
RWE		
100% Power	0.27	1.00
85% Power	0.28	1.00
65% Power	0.36	1.00
40% Power	0.58	1.00

Conclusion

The NRC staff has reviewed the licensee's analyses of the excess heat removal events described above and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed EPU 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 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 GDC-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 an unplanned decrease 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 which is capable of making the core subcritical under any conditions (including anticipated operational transients) sufficiently fast to prevent 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

The licensee evaluated the following transients for Browns Ferry under EPU conditions using the approved methods in FUSAR (Reference 164):

1. Load rejection no bypass (LRNB)
2. Turbine trip no bypass (TTNB)

LRNB and TTNB are performed for every BFN reload evaluation. TVA stated that the steam pressure regulator failure closed event is not part of the Browns Ferry design basis, since the installation of the new digital fault tolerant turbine control system eliminated the event as an AOO; therefore, this event was not analyzed. Generic evaluation of BWR EPUs (ELTR1 (Reference 49)) confirms that the loss of condenser vacuum with bypass available event is similar to a turbine trip and is bounded by the results of the TTNB event; therefore, this event was also not analyzed. Closure of an MSIV event is addressed in Section 2.8.4.2 of this SE.

The LRNB and TTNB events' ΔCPR values are shown in Section 2.8.5.1 of this SE. These events are not limiting for defining the OLMCPR because they are bounded by the FWCF event which results in the largest ΔCPR at power operation and has the greatest impact on SAFDLs.

The NRC staff concludes that the licensee adequately addressed LRNB and TTNB transients in its submittals. Therefore, the staff finds this acceptable.

Conclusion

The NRC staff has reviewed the licensee's evaluations 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 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 GDC-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 Nonemergency AC Power to the Station Auxiliaries

Regulatory Evaluation

The loss of nonemergency AC power is assumed to result in the loss of all power to the station auxiliaries and the simultaneous tripping of all reactor coolant 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 making the core subcritical under any conditions (including anticipated operational transients) sufficiently fast to prevent 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

Loss of auxiliary power can occur if all external grid connections are lost or if faults occur in the auxiliary power system itself causing two types of transients: Loss of auxiliary power transformers and loss of auxiliary power grids. Because operating pressure does not change as a result of this EPU, operation at EPU conditions will not affect the key parameters of this event – MSRV pressure setpoint, pump trip setpoints, MSIV trip setpoint, pump coastdown rates, scram setpoints, etc. Generic evaluation of BWR EPUs confirms that loss of auxiliary power is bounded by the loss of feedwater flow long-term water level transient, and the ΔCPR and vessel pressure for the loss of auxiliary power event is bounded by the LRNB event. Therefore, the licensee concluded that an analysis of this event is not required for the EPU because it is not limiting with respect to ΔCPR. The NRC staff concurs with this evaluation.

As stated earlier, Table E-1 of ELTR1 (Reference 49) provides a list of transients that are to be addressed in the power uprate submittal. According to the ELTR1 evaluation, loss of auxiliary power to the station auxiliaries is a non-limiting event for all GE BWRs. Therefore, this event is not analyzed. The NRC staff finds this is acceptable because the loss of auxiliary power to the station auxiliaries event is not limiting with respect to impact on SAFDLs.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the loss of nonemergency AC power to station auxiliaries' event and concludes that the licensee's evaluation has adequately accounted for operation of the plant at the proposed power level. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to

ensure that the SAFDLs 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 GDC-6 and 29 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the loss of nonemergency AC power to station auxiliaries' event.

2.8.5.2.3 Loss of Normal Feedwater Flow

Regulatory Evaluation

A loss of normal feedwater flow could occur from pump failures, valve malfunctions, or a LOOP. Loss of feedwater flow results in an increase in reactor coolant temperature and pressure 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; and (2) draft GDC-29 insofar as it requires that a reactivity control system be provided capable of making the core subcritical under any conditions (including anticipated operational transients) sufficiently fast to prevent 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

The licensee performed (refer to FUSAR (Reference 164) a calculation of the loss of feedwater flow (LOFW) event without credit for HPCI operation and only the RCIC operational. The acceptable criterion for this event is to maintain the shroud water level above the top of active fuel such that the core remains coolable during the transient without exceeding SAFDLs. EPU conditions affect this event because it takes longer to restore water level due to the higher operating power and higher decay heat. The licensee's analysis results indicated that the minimum water level reached during the event is 66 inches above the top of active fuel, which meets the acceptance criteria and is above the Level 1 ADS actuation setpoint for water level. This analysis demonstrated acceptable RCIC performance under EPU conditions; therefore, it is acceptable to the NRC staff.

In addition, the licensee performed (refer to FUSAR (Reference 164) an analysis to evaluate the loss of a single feedwater pump event at Browns Ferry. This analysis demonstrates that BFN with an equilibrium ATRIUM 10XM core maintains water level 10 inches above the Level 3 setpoint for water level, which prevents an unnecessary automated plant scram for this event; therefore, this is acceptable to the NRC staff.

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 acceptance criteria for RPV water level and the SAFDLs 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 GDC-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 specified acceptable fuel design limits (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 making the core subcritical under any conditions (including anticipated operational transients) sufficiently fast to prevent 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

NRC-approved generic analyses performed for several BWRs (ELTR1 (Reference 49)) have shown that the events in this category are not limiting and are bounded by other more limiting transients. Therefore, these events are not included in Table E-1 of ELTR1 for the EPU evaluation.

TVA confirmed that the recirculation pump trip (RPT) or two recirculation pump trip (2RPT) events have no impact on fuel integrity because the ΔCPR margin increases during RPT events. Thus, RPT events are not analyzed under EPU conditions because the consequences, if any, are bound by the analyzed TTNB event results.

The RPT event of a single pump has no impact on fuel integrity. Neutron flux, surface heat flux, vessel pressure, and steam line pressure do not exceed their initial values. This event is bound by TTNB. Therefore, analysis of this event is not required for the EPU.

The consequences of a recirculation flow controller failure (reduced flow) are less severe than RPT events and are not analyzed for the EPU because they are bounded by the pump trip evaluation.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the decrease in reactor coolant flow event and concludes that the licensee's evaluation has adequately accounted for operation of the plant at the proposed power level. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs 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 GDC-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) final GDC-27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; (2) 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 (3) draft GDC-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 and 4 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

Generic evaluation of BWR EPUs, approved by the NRC (ELTR1, (Reference 49)), demonstrated that the typical ΔCPR for this event is of the order of 0.10, which is non-limiting, and is not a challenge to the RCPB safety limits. Therefore, re-analysis of this event is not required under EPU conditions, and it is not included in Table E-1 of ELTR1 for EPU evaluation. Further, the licensee confirmed, in Section 2.8.5.3.2 of the FUSAR, that the consequences of a

pump seizure event have been analyzed previously in NEDC-33004P-A (Reference 48) and found not to be limiting under any circumstances.

Since there are no changes to recirculation pumps, the staff finds that Browns Ferry will continue to meet the limits during EPU operation. The NRC staff concludes that the Browns Ferry RCPB is designed with sufficient margin for this non-limiting event and is equipped with effective reactivity control systems. The pump shaft break event is bounded by the pump seizure event. Therefore, analysis of this event is not required for the EPU.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the sudden decrease in core coolant flow events and concludes that the licensee's evaluation has adequately accounted for operation of the plant at the proposed power level. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the ability to insert control rods is maintained, the RCPB pressure limits will not be exceeded, the RCPB will behave in a non-brittle manner, the probability of propagating fracture of the RCPB is minimized, and adequate core cooling will be provided. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of final GDC-27 and draft GDC-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 Withdrawal from a Subcritical or Low Power Startup Condition

Regulatory Evaluation

An uncontrolled control rod 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) final GDC-10, insofar as it requires that the RCS be designed with appropriate margin to ensure that specified acceptable fuel design limits (SAFDLs) are not exceeded during normal operations, including AOOs; (2) draft GDC-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 criteria used in the evaluation of the uncontrolled control rod withdrawal from a subcritical or low power startup condition event for the EPU is a comparison of the expected maximum increase in peak fuel enthalpy to the acceptance criterion of 170 calorie (cal)/gram fuel enthalpy, which is the SAFDL for this transient event.

There is no change to the reactor manual control system or control rod hydraulic control units for EPU. The rod worth minimizer (RWM) installed provides the same level of protection for the AREVA fuel following EPU as at CLTP provided the power increase is less than or equal 120 percent of OLTP. This event initiates from subcritical or low-power conditions and is, therefore, not affected by the EPU power increase at full power. TVA evaluated the event using the NRC-approved methodologies (see FUSAR (Reference 164)), an equilibrium ATRIUM 10XM core, and a conservative multiplier of 1.2 and calculated a maximum rod withdrawal error (RWE) peak fuel enthalpy of 72 cal/gram, which is below the Browns Ferry 170 cal/gram conservative acceptance criterion. Therefore, the NRC staff finds the licensee's evaluations of this event acceptable.

Conclusion

The NRC staff has reviewed the licensee's analyses of the uncontrolled control rod 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 final GDC-10 and draft GDC-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 Withdrawal at Power

Regulatory Evaluation

An uncontrolled control rod 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) final GDC-10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) draft GDC-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

Analyses of rod withdrawal at power is part of the reload analysis process and contributes to the setting of the cycle-specific operating limit minimum critical power ratio (OLMCPR). The analysis is performed using approved methodologies (MICROBURN-B2, ACE CPR correlation, and RODEX4) and specifically accounts for the core configuration, including the ATRIUM-10XM loading pattern and fuel thermal conductivity degradation. The licensee provided results for a representative equilibrium ATRIUM-10XM core in Section 2.8.5.4.2 of the FUSAR and the resulting ΔCPR is 0.27, which is not limiting because it is bounded by the FWCF event (the FWCF is the limiting event with ΔCPR of 0.34).

Conclusion

The NRC staff has reviewed the licensee's analyses of the uncontrolled control rod 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 final GDC-10 and draft GDC-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) final GDC-10, insofar as it requires that the RCS be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs; (2) draft GDC-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; (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

The fast recirculation pump flow runup event involves an unplanned increase in core coolant flow resulting from a control system malfunction. The rapid increase in core inlet flow causes a large neutron flux peak which may scram the reactor. Generally, this event is non-limiting compared to other AOO events.

The licensee analyzed two flow-rate-increase events to confirm that this event is non-limiting for Browns Ferry: fast and slow flow run-ups. Neither event is limiting with respect to ΔCPR. The fast flow increase results in a ΔCPR of 0.13, which is not limiting (see Section 2.8.5.1 of this safety evaluation). The slow flow increase does not result in a scram or challenge fuel limits, but it is used to set the flow-dependent operating limits to ensure that at the end of the flow run-up, full power operating limits are not violated. The licensee analyzed the slow flow run-up event on a cycle-specific basis with approved methods (refer to FUSAR (Reference 164)) as part of the reload process; thus, the impact of the EPU and future core loading patterns will be accounted for by the cycle-specific analyses. The fast recirculation pump flow run-up event is not analyzed on a cycle-specific basis because it is not limiting. However, as stated above, TVA provided a fast recirculation pump flow run-up event analysis for an equilibrium ATRIUM 10XM EPU core to confirm the event remains non-limiting at EPU conditions.

The startup of an idle recirculation loop event is non-limiting compared to other AOO events, as shown by the generic evaluation of BWR EPUs (ELTR1 (Reference 49)). Therefore, this event is not listed in Table E-1 of ELTR1 as a transient analysis to be performed for an EPU and is not required to be analyzed for the EPU.

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 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 final GDC-10 and draft GDC-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 context 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 licensee evaluated control rod drop accidents at power on a cycle-specific basis using the approved methods described in XN-NF-80-19(P)(A) (Reference 229). The acceptance criteria are: peak fuel enthalpy less than 280 cal/gram and less than 850 rod failures to maintain the radiological assessment valid. Each cycle is specifically evaluated based on the actual core loading and projected operation.

TVA provided the results of a series of rod drop event analyses for an equilibrium ATRIUM 10XM EPU core. The calculated peak fuel enthalpy for the hottest rod is 142 cal/gram, which is below the acceptance limit of 280 cal/gram or the fuel failure threshold of 170 cal/gram; thus, no failed fuel rods are predicted and the acceptance criteria are satisfied. Therefore, the results are acceptable.

Conclusion

The NRC staff has reviewed the licensee's analyses of the rod drop accident and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed EPU 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) final GDC-10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; 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

The main purpose of the high-pressure coolant injection (HPCI) system is to provide makeup water to the reactor vessel during a small break LOCA that does not rapidly depressurize the reactor vessel. The inadvertent HPCI pump start (IHPS) event involves an increase in the vessel inventory due to the inadvertent injection of HPCI flow into the core which may threaten thermal margins.

The IHPS event is not analyzed on a cycle-specific basis because it is not limiting. However, TVA provided (FUSAR (Reference 164)) an IHPS analysis for an equilibrium ATRIUM-10XM EPU core to confirm that the event remains non-limiting at EPU conditions. The licensee's analysis results indicate that IHPS remains non-limiting (see the Table in Section 2.8.5.1 of this safety evaluation). The ΔCPR for IHPS is 0.16; which is non-limiting and bounded by the limiting AOO (FWCF). The analyses also confirm that the Level 8 setpoint for high RPV water level is not reached, so a turbine trip would not be initiated for this event. Therefore, the NRC staff finds this is acceptable.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the inadvertent operation of ECCS or malfunction that increases reactor coolant inventory and concludes that the licensee's evaluation has 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 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 final GDC-10, and draft GDC-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 (CST) via the condenser hotwell. The NRC staff's review covered (1) the sequence of events, (2) the analytical model used for analyses, (3) the values of parameters used in the analytical model, and (4) the results of the transient analyses. The NRC's acceptance criteria are based on (1) final GDC-10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal

operations, including AOOs; and (2) draft GDC-29 insofar as it requires that a reactivity control system be provided capable of making the core subcritical under any conditions (including anticipated operational transients) sufficiently fast to prevent 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

The inadvertent opening of a relief valve (IORV) event is not typically analyzed because it results in a mild depressurization that reduces power level, the peak heat flux does not exceed the initial power, and the event never challenges SAFDLs. Since this event has no potential of being limiting, it is not required to be reanalyzed under EPU operating conditions.

The IORV event is not listed in Table E-1 of the ELTR1 (Reference 49) to be analyzed for an EPU. Consistent with the ELTR1, the IORV event is not included in the list of transients because it is not limiting for any GEH BWR with respect to MCPR as the event results in a small power change. In addition, the steam pressure regulator stays in service during this event to control reactor pressure.

This event will have a slight effect on fuel thermal margins. The change in surface heat flux is expected to be negligible indicating an insignificant change in the minimum critical power ratio (MCPR). According to ELTR1, the bounding event for this category (decrease in reactor coolant inventory) is loss of feedwater. Thus, this transient is not listed in the minimum required analyses in ELTR1 and hence is was not analyzed.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the inadvertent opening of a pressure relief valve event and concludes that the licensee's evaluation has adequately accounted for operation of the plant at the proposed power level. 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 final GDC-10 and draft GDC-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 the licensee's determination of break locations and break sizes; (1) postulated initial conditions; (2) the sequence of events; (3) the analytical model used for analyses, and calculations of the reactor power, pressure, flow, and temperature transients; (4) calculations of peak cladding temperature, total oxidation of the cladding, total hydrogen generation, changes in core

geometry, and long-term cooling; (5) functional and operational characteristics of the reactor protection and ECCS systems; and (6) 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 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) final GDC-35, insofar as it requires that a system to provide abundant emergency core cooling be provided to transfer heat from the reactor core following any LOCA at a rate so that fuel clad damage that could interfere with continued effective core cooling will be prevented. Specific review criteria are contained in SRP Sections 6.3 and 15.6.5 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

The primary impacts of an EPU on LOCA events are the initial stored energy (higher average fuel pellet temperatures) and the increase in decay heat levels. Browns Ferry reactors are small-break LOCA limited, and changes in initial stored energy have no significant effect on the BWR LOCA because the stored energy is released during the blowout part of the transient, when there is plenty of heat transfer available between the fuel and the boiling coolant. For the decay heat model, AREVA uses the 11 group equation curve fit to the 1971 draft ANS standard for fission product decay with a conservative 1.2 multiplier, and explicitly accounts for the increase in decay heat due to the EPU.

To model advanced fuel features like part length rods, AREVA has implemented new [[ ]] to evaluate the radiation view factors that directly account for the advanced fuel geometry.

Other changes to the NRC approved EXEM BWR-2000 model (Reference 230) were implemented and documented in Appendix B of ANP-2860P, Supplement 2 (Reference 69), including a [[

]].

Thermal conductivity degradation (TCD) for ECCS evaluations is not explicitly modeled by RODEX2, which is used to generate the fuel mechanical parameters for ECCS calculations. To conservatively apply the effects of TCD, AREVA methods use [[

]]. The limiting PCT occurs at beginning of life exposure. Therefore, the overall limiting PCT is not affected by TCD.

The analyses of a LOCA are described in Browns Ferry UFSAR Section 14.6.3. The ECCS components are designed to provide protection in the event of a LOCA due to a rupture of the primary system piping. Although design basis accidents (DBAs) are not expected to occur during the lifetime of a plant, plants are designed and analyzed to ensure that the radiological dose from a DBA will not exceed the 10 CFR 50.67 limits. For a LOCA, 10 CFR 50.46 specifies design acceptance criteria based on (a) the peak cladding temperature (PCT), (b) local cladding oxidation, total hydrogen generation, (c) coolable core geometry, and (d) long-term cooling. The LOCA analysis considers a spectrum of break sizes and locations, including a rapid

circumferential rupture of the largest recirculation system pipe. Assuming a single failure of the ECCS, the LOCA analysis identifies the break sizes that most severely challenge the ECCS systems and the primary containment. The maximum average planar linear heat generation rate (MAPLHGR) operating limit is based on the most limiting LOCA analysis, and licensees perform LOCA analyses for each new fuel type to demonstrate that the 10 CFR 50.46 acceptance criteria can be met.

The ECCS for Browns Ferry includes the high pressure coolant injection (HPCI) system, the low pressure coolant injection (LPCI) system, the low pressure core spray (LPCS) system, and the automatic depressurization system (ADS).

High Pressure Coolant Injection (HPCI) System

The modeled characteristics of the HPCI system are provided in Table 4.4 of ANP-3377NP (Reference 57). The HPCI system provides reactor vessel coolant inventory makeup in the event of a small break LOCA that does not immediately depressurize the reactor vessel and helps to depressurize the reactor vessel.

There is no change following EPU implementation to the maximum specified reactor pressure for HPCI system operation and no change in the HPCI system performance parameters. The maximum injection pressure for the HPCI system is conservatively based on the upper allowable value for the lowest available group of SRVs. Because the SRV settings and the normal reactor operating pressure remain the same for the EPU, the HPCI system operating conditions and operating functions also remain the same. Therefore, there is no change in the original design pressures or temperatures for the system components.

Because the maximum normal operating pressure and the SRV setpoints do not change for the EPU, the HPCI system performance requirements do not change. The licensee's ECCS-LOCA analysis (see section titled, "ECCS Performance" for evaluation) with the current HPCI capability demonstrated that the system provides adequate core cooling. Therefore, the NRC staff finds the evaluation acceptable, and agrees with the licensee's assessment that the HPCI system will continue to meet the NRC's acceptance criteria, as outlined in the Regulatory Evaluation section above.

Low Pressure Coolant Injection (LPCI) System

The modeled characteristics of the LPCI system are provided in Table 4.5 of ANP-3377NP (Reference 57). The LPCI mode of the RHR system is automatically initiated in the event of a LOCA. The primary purpose of the LPCI mode is to help maintain reactor vessel coolant inventory for a large break LOCA and for any small break LOCA after the reactor vessel has depressurized. The LPCI operating requirements are not affected by the EPU and the ECCS performance evaluation demonstrates the adequacy of the LPCI core cooling performance.

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

Low Pressure Core Spray (LPCS) System

The modeled characteristics of the LPCS system are provided in Table 4.6 of ANP-3377NP (Reference 57). The LPCS system is automatically initiated in the event of a LOCA. When operating in conjunction with other ECCSs, the LPCS system is required to provide adequate core cooling for all LOCA events. There is no change in the reactor pressures at which the LPCS is required. The LPCS system sprays water into the reactor vessel after it is depressurized, and the LPCS system cooling is not credited until the time of rated spray. The primary purpose of the LPCS system is to provide reactor vessel coolant inventory makeup for a large break LOCA and for any small break LOCA after the reactor vessel has depressurized. It also provides long-term core cooling in the event of a LOCA.

The licensee stated that the change in the system operating conditions due to the EPU for a postulated LOCA does not affect the hardware capabilities of the LPCS system. Core spray distribution is not directly credited in the short-term cooling for LOCA analyses. This is consistent with ECCS evaluation models specified in Appendix K to 10 CFR Part 50. Therefore, the convective heat transfer coefficients used during the short-term spray cooling period are the conservative values specified in Appendix K. The LPCS system functions are not changed and the core cooling capacity remains adequate.

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

Automatic Depressurization System (ADS)

The ADS reduces pressure during a small break LOCA resulting in an earlier initiation of low pressure ECCS. The modeled characteristics of the ADS system are provided in Table 4.7 of ANP-3377P, Rev. 3 (Reference 57). The ADS uses a number of the SRVs to reduce the reactor pressure following a small break LOCA when it is assumed that the high-pressure systems have failed. After a specified delay, the ADS actuates either on low water level plus high drywell pressure or on sustained low water level alone. This allows the LPCS and LPCI to inject coolant into the reactor vessel. Plant design requires a minimum flow capacity for the SRVs, and requires that the ADS initiates following confirmatory signals and associated time delay(s). The required flow capacity and ability to initiate the ADS on appropriate signals are not affected by the EPU. The ADS initiation logic and ADS valve control are not affected, and are adequate for EPU conditions.

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

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

ECCS Performance

The ECCS is designed to provide protection against postulated LOCAs caused by ruptures in the primary system piping. The ECCS performance under all LOCA conditions and the analysis models must satisfy the requirements of 10 CFR 50.46 and 10 CFR Part 50, Appendix K. The NRC-approved EXEM BWR-2000 (Reference 230) evaluation model was used for the equilibrium core LOCA analysis.

The purpose of the LOCA analyses is to define maximum values for the maximum average planar linear heat generation rate (MAPLHGR) that ensure compliance with the LOCA-ECCS criteria in 10 CFR 50.46. These break spectrum analyses were performed under EPU operating conditions for an equilibrium ATRIUM-10XM cycle and documented in ANP-3377P (Reference 57). The Browns Ferry MAPLHGR analysis for ATRIUM 10XM and ATRIUM-10 fuel are documented in ANP-3378P (Reference 58) and ANP-3384P (Reference 59), respectively.

The LOCA analyses assume a loss of offsite power plus the limiting single failure for a two loop operation (TLO). A number of potential limiting single failure events were analyzed for each break location, and they are documented in Table 5.1 of ANP-3377P (Reference 57). The limiting single failure was determined to be the failure of a single backup battery board.

Section 5 of ANP-3377P (Reference 57) describes the assumptions used in the break-spectrum analyses, and Section 6 documents the results, which can be summarized as follows:

1. The limiting (highest PCT) recirculation line break is the 0.23 ft^2 split break in the pump discharge piping with a single backup battery board failure and a top-peaked axial power shape. The limiting PCT is 2030 °F and maximum local cladding oxidation is 1.99 percent, which satisfies the acceptance criteria. A full spectrum of break locations, sizes, mid- and top-peaked axial power shapes, and single failures were analyzed. The calculated results show adequate margin to the 2200 °F acceptance criterion for the PCT.

2. The limiting non-recirculation line break is the 0.4 ft^2 double-ended guillotine (DEG) break in the low pressure core spray (LPCS) line with a single backup battery board failure and a top-peaked axial power shape. The PCT for the limiting ECCS line break is [[ ]] and the maximum local cladding oxidation is 0.11 percent, which is acceptable.

Using the limiting break size and location identified in ANP-3377P (Reference 56), Browns Ferry performed a MAPLHGR analysis for both ATRIUM 10XM in ANP-3378P (Reference 58) and ATRIUM-10 in ANP-3384P (Reference 59). The HUXY heatup analysis from the approved EXEM BWR-2000 ECCS Evaluation (Reference 230) is used for this analysis.

The impact of thermal conductivity degradation (TCD) has been included in the analysis, even though the older HUXY/RODEX2 methodology does not have explicit TCD models. [[

]]

The LOCA event analyses indicate that Browns Ferry is small break LOCA limited. The limiting PCT is controlled by the hot bundle power, which is not significantly impacted by EPU operation

because it is assumed to be operating at the thermal limits (MCPR, MAPLHGR, and LHGR), and these limits are not changed for the EPU.

Based on the above analyses, MAPLHGR values have been developed as a function of exposure for ATRIUM 10XM (Table 5-2 of ANP-3378P (Reference 58)) and ATRIUM-10 (Table 5-2 of ANP-3384P (Reference 59)). The results of the LOCA analyses demonstrate the adequacy of the Browns Ferry ECCS (which includes HPCI, LPCI, LPCS, and ADS) because of the acceptable results of the break spectrum analyses.

For single loop operation (SLO) a multiplier is applied to the MAPLHGR limits for the TLO. The SLO multiplier is established such that the PCT for SLO is bounded by the limiting PCT for the TLO. The SLO evaluation for Browns Ferry continues to support a SLO MAPLHGR multiplier of 0.85 in order to bound the results of the TLO evaluation. The SLO MAPLHGR multiplier is not impacted by the EPU. At EPU power condition, the MELLLA core flow extends to approximately 99 percent of rated core flow. Therefore, the EPU analysis results at rated power and flow are applied to the MELLLA condition. Also, the effect of increased core flow (ICF) (105 percent of rated core flow) on PCT is negligible with EPU conditions. Thus the SLO, MELLLA, and ICF domain remain valid with the EPU.

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

a) The NRC staff's evaluations of several licensees' requests for stretch power increase and EPU at BWRs have shown that the change of PCT for power uprates is not significant. The maximum increase in the PCT was small, and was well within the acceptance criteria of 10 CFR 50.46.

b) The ECCS performance characteristics and basic break spectrum response are not affected by an EPU.

c) The limiting break sizes are well known and have been shown not to be a function of reactor power level.

d) The analyses assume the hot bundle continues to operate at the thermal limits (MCPR, MAPLGHR, and LHGR) which are not changed by the EPU.

e) The PCT for the limiting large-break LOCA is determined primarily by the hot bundle power, which is expected to increase by a small amount with the power uprate.

In conclusion, the NRC staff reviewed the proposed ECCS evaluation results for the EPU by comparing them to the prior analyses of record and determined that the predicted PCTs were reasonably consistent, and that differences in the break spectrum and limiting results were acceptable.

Based on the licensee's plant-specific LOCA analysis for the Browns Ferry EPU condition with equilibrium core, and because the licensee will perform plant cycle-specific evaluations of ECCS-LOCA performance for Browns Ferry's first EPU cycle using approved methods, as required in Section 5.2 of ELTR-2 (Reference 50), the NRC staff agrees with the licensee that the Browns Ferry ECCS-LOCA performance complies with 10 CFR 50.46 and 10 CFR Part 50, Appendix K requirements.

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 final GDC-35 and draft GDC-40 and 42, 10 CFR 50.46, and 10 CFR Part 50, Appendix K following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to a LOCA.

2.8.5.7 Anticipated Transients Without Scrams (ATWS)

Regulatory Evaluation

ATWS is defined as an AOO followed by the failure of the reactor portion of the protection system specified in draft GDC-14 and 15. The regulation at 10 CFR 50.62 requires 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 system (SLCS) with the capability of injecting into the reactor vessel a borated water solution with reactivity control at least equivalent to the control obtained by injecting 86 gpm of a 13 weight-percent sodium pentaborate decahydrate solution at the natural boron-10 isotope abundance into a 251-inch inside diameter reactor vessel. The system initiation must be automatic.

- Each BWR have equipment to trip the reactor coolant recirculation pumps automatically under conditions indicative of an ATWS.

The NRC staff's review was conducted to ensure that (1) the above requirements are met, (2) sufficient margin is available in the setpoint for the SLCS pump discharge relief valve such that SLCS operability is not affected by the proposed EPU, and (3) operator actions specified in the plant's Emergency Operating Instructions 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 cladding temperature is within the 10 CFR 50.46 limit of 2200 °F; (3) the peak suppression pool temperature is less than the design limit; and (4) the peak containment pressure is less than the containment design pressure. The NRC staff also evaluated the potential for thermal-hydraulic instability in conjunction with ATWS events using the methods and criteria approved by the NRC staff. For this analysis, the NRC staff reviewed the limiting event determination, the sequence of events, the analytical model and its applicability, the values of parameters used in the

analytical model, and the results of the analyses. Review guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

An ATWS event starts when an AOO occurs and the control rods cannot be inserted to scram the reactor. Due to strong reactivity feedback, reactor power and pressure rise rapidly to reach maximum values and challenge the reactor coolant pressure boundary and thermal design limits. Eventually the SLCS will inject a boron solution into the core after the first safety relief valve opens to relieve reactor pressure. It brings the reactor to a subcritical state from the hot full power condition and remains a subcritical until the reactor cools down to the cold-shutdown condition. For every reload, the licensee evaluates how plant modifications, reload core designs, changes in fuel design, and other reactor operating changes affect the ATWS analysis.

The licensee performed ATWS over-pressurization analyses using COTRANSA2, which is an NRC-approved method for these analyses (Reference 228). Two isolation events without scram were analyzed: Main steam isolation valve closure (MSIVC) and pressure regulator failure open (PRFO). PRFO produces the maximum overpressure value of 1469 psia, which is below the ASME Service Level C Limit of 1500 psig. One safety relief valve (SRV) was assumed out of service. AREVA verified that the bypass flow was strongly upwards for the short-term over-pressurization events and, thus, the COTRANSA2 models were within their range of applicability. A computation time step and nodalization study was also conducted to confirm that numerical diffusion did not significantly impact the results.

With respect to long term cooling and containment response during ATWS, Browns Ferry has performed a comparative analysis to evaluate the impact of ATRIUM-10XM fuel versus GE14 and documented it in Section 2.8.5.7.2 and Table 2.8-16 of the FUSAR (Reference 164). The results of these sensitivity analyses indicate little or no change to the final suppression pool temperature with a GE14 core or an ATRIUM-10XM core (less 1 °F) and the changes to total energy release to the suppression pool with different fuel loadings are insignificant. Thus, the EPU analysis of record documented in the PUSAR (Reference 47) remains applicable to the ATRIUM 10XM equilibrium core and the transition cores. The peak suppression pool temperature and containment pressure results (173.3 °F and 8.7 psig for the limiting LOOP event) are well below the containment design temperature and pressure (281 °F and 56 psig).

There is no core uncovery associated with the analyzed ATWS events, hence the PCT and local cladding oxidation results are bounded by the LOCA analyses, and are acceptable.

ATWS with instability (ATWSI) calculations are only required for operating domain extensions like MELLLA+ and extended flow window. Therefore, ATWSI calculations have not been performed for the Browns Ferry EPU LAR.

In addition, Browns Ferry meets the ATWS mitigation requirements defined in 10 CFR 50.62: installation of an alternate rod injection (ARI) system; SLCS boron injection equivalent to 86 gpm of 13 weight percent natural boron; and installation of automatic RPT logic.

In response to an NRC staff's RAI, the licensee confirmed in its letter dated April 4, 2016 (Reference 11), that the SLCS relief valve margin for the EPU was 33 psi. The 33 psi margin takes into account the SLCS relief valve setpoint tolerance (drift) of plus or minus 75 psi (taken from the SLCS relief valve nominal setpoint of 1425 psig) plus an additional margin of 30 psi for

SLCS pump pulsation, plus elevation head and line loss differences between the SLCS pump and the relief valve inlet piping. Considering that the evaluation takes into account the relief valve drift and compensation for pump pressure pulsations in the 33 psi margin, the staff finds that sufficient margin remains available in the setpoint for the SLCS pump discharge relief valve, and is acceptable.

The licensee further confirmed in its letter dated April 4, 2016 (Reference 11), that no changes to any operator instruction, including the emergency operating procedures (EOPs) and the emergency procedure and severe accident guidelines (EPGs/SAGs) that are applicable to Browns Ferry, are needed for the EPU. The EOPs being implemented at Browns Ferry are based on EPGs Revision 3.

As part of the containment evaluation, Section 2.6 of the PUSAR contains a thorough evaluation of the ECCS pumps net positive suction head (NPSH) requirements during containment-challenging events such as an ATWS. A summary of all these requirements is contained in Table 2.6-4 of the PUSAR. The NRC staff evaluation of the suppression pool temperature response and NPSH of ECCS pumps during an ATWS is discussed in Sections 2.6.5.1 and 2.6.5.2 of this SE.

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

Conclusion

The NRC staff has reviewed the information submitted by the licensee related to an ATWS and concludes that the licensee has adequately accounted for the effects of the proposed EPU on an ATWS. The NRC staff concludes that the licensee has demonstrated that ARI, SLCS, 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

In Attachment 8 (FUSAR) of the LAR (Reference 1), the licensee addressed the impact of the EPU on the spent fuel pool (SFP) nuclear criticality safety (NCS) analyses. During the acceptance review, the NRC staff determined that a review of the NCS analysis of record would be necessary. The licensee provided AREVA document ANP-3160, Revision 1 by letter dated December 15, 2015 (Reference 3).

ANP-3160 presents the NCS analysis for the Browns Ferry spent fuel storage racks. The report describes the methodology and analytical models used in the NCS analysis to show that the spent fuel storage racks' maximum k-effective will be no greater than 0.95 when flooded with unborated water. Appendix C of ANP-3160 also includes the benchmarking evaluation performed for the SCALE 4.4a code package used for the NCS analysis, to demonstrate the

applicability of the code to geometries and compositions being analyzed and to determine the code bias and uncertainty.

The three BFN units each contain identical SFP layouts with fourteen 13x13 storage modules and five 13x17 storage modules. All storage modules contain Boral neutron-absorbing material that is credited to meet NRC subcriticality requirements. Since the fuel assembly designs and SFP configuration is the same in all three SFPs, a single criticality analysis was performed to bound all SFP storage cells in the Browns Ferry SFPs.

The TVA TSs currently prohibit fuel storage in the new fuel storage racks. The proposed EPU operation would not change this part of the TVA licensing basis.

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 draft GDC-66, insofar as it requires the prevention of criticality in fuel storage systems by physical systems or processes, preferably utilizing geometrically safe configurations, and 10 CFR 50.68. Specific review criteria are contained in SRP Sections 9.1.1 and 9.1.2.

Technical Evaluation

The licensee currently prohibits use of the Browns Ferry new fuel storage vault for storage of any fuel assemblies, in accordance with TS 4.3.1.2. If there is no fuel stored in the new fuel storage vault, then there is nothing further to address for prevention of criticality as per draft GDC-66 or 10 CFR 50.68. New fuel is bounded by the criticality analysis discussed in Section 2.8.6.2, so the licensee may use the SFP storage racks for this purpose.

Conclusion

The NRC staff has reviewed the licensee's current licensing basis related to the new fuel storage facilities and concludes that the new fuel storage facilities will continue to meet the requirements of draft GDC-66 and 10 CFR 50.68 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the new fuel storage.

2.8.6.2 Spent Fuel Storage

Regulatory Evaluation

Nuclear reactor plants include storage facilities for the wet storage of spent fuel assemblies. The safety function of the SFP and storage racks is to maintain the spent fuel assemblies in a safe and subcritical array during all credible storage conditions and to provide a safe means of

loading the assemblies into shipping casks. The NRC staff's review covered the effect of the proposed EPU on the criticality analysis (e.g., reactivity of the spent fuel storage array and Boral degradation or neutron poison efficacy). The NRC's acceptance criteria are based on (1) draft GDC-4, insofar as it requires SSCs important to safety shall not be shared among nuclear power units unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions, including, in the event of an accident in one unit, an orderly shutdown and cooldown, and (2) draft GDC-66, 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 Standard Review Plan (SRP) Section 9.1.1, "Criticality Safety of Fresh and Spent Fuel Storage and Handling," Revision 3, and SRP Section 9.1.2, "New and Spent Fuel Storage," Revision 4.

Paragraph 50.68(b)(1) of 10 CFR requires, "Plant procedures shall prohibit the handling and storage at any one time of more fuel assemblies than have been determined to be safely subcritical under the most adverse moderation conditions feasible by unborated water."

Paragraph 50.68(b)(4) of 10 CFR requires, in part, "If no credit for soluble boron is taken, the k-effective of the spent fuel storage racks loaded with fuel of the maximum fuel assembly reactivity must not exceed 0.95, at a 95-percent probability, 95-percent confidence level, if flooded with unborated water."

In addition, paragraph 50.36(c)(4) of 10 CFR requires, in part, "Design features. Design features to be included are those features of the facility such as materials of construction and geometric arrangements, which, if altered or modified, would have a significant effect on safety."

Regulatory Guidance

The NRC staff issued a memorandum dated August 19, 1998 (Reference 231), also known as the "Kopp Memo," containing staff guidance for performing the review of SFP NCS analyses. This guidance supports determining compliance with GDC-62 and existing SRP Sections 9.1.1 and 9.1.2. The principal objective of this guidance was to clarify and document staff positions that may have been incompletely or ambiguously stated in previously issued safety evaluations and other staff documents. A second purpose was to state staff positions on a number of strategies used in SFP NCS analyses at that time.

The Division of Safety System (DSS) Interim Staff Guidance (ISG) DSS-ISG-2010-01 (Reference 232) provides updated guidance to address the increased complexity of recent SFP nuclear criticality analyses and operations. The guidance is intended to reiterate existing guidance, clarify ambiguity in existing guidance, and identify lessons learned based on recent submittals. Similar to the Kopp Memo, this guidance supports determining compliance with GDC-62 and following the guidance described in SRP, Sections 9.1.1 and 9.1.2.

Draft GDC-66 under which Browns Ferry was licensed is equivalent to the current GDC-62 that the Kopp Memo and DSS-ISG-2010-01 were published to support. Accordingly, this guidance can be used to support a finding under draft GDC-66 for BFN.

Method of Review

The NRC staff's safety evaluation involved a review of the data provided by the licensee to demonstrate that if its TS requirements, as amended by its proposed changes, are satisfied,

then compliance with the relevant NRC requirements for SFP subcriticality will be assured. The review was performed consistent with SRP, Section 9.1.1 and existing guidance on SFP NCS analyses captured by the Kopp Memo (Reference 231) and DSS-ISG-2010-01 (Reference 232). While SRP, Section 9.1.2 is applicable, it does not concern itself directly with criticality safety considerations in fuel storage, therefore Section 9.1.1 contains the primary SRP guidance for reviewing the proposed changes in the LAR as supplemented.

Fuel assemblies can be moved between the SFPs associated with BFN Units 1 and 2, but the NCS analysis is intended to bound all fuel that can be stored in any of the BFN SFPs. The Unit 3 SFP is not connected to the other two SFPs via a channel capable of transferring fuel, so similar considerations are not applicable. The separation between the SFPs is sufficient to ensure that there is no neutronic coupling between the SFPs. Therefore, no review was performed to examine any shared functionality of the BFN SFPs.

Proposed Technical Specifications Change

The licensee is proposing a new TS 4.3.1.1.b, with the existing TS 4.3.1.1.b moved to TS 4.3.1.1.c. The proposed change to TS 4.3.1.1.c will incorporate a k-infinity limit for fuel stored in the BFN SFP racks. The intent of the NCS analyses is to demonstrate that regulatory compliance is assured as long as all fuel loaded in the BFN SFP racks is of one of the analyzed fuel assembly designs, and satisfies the TS k-infinity limit. The k-infinity of candidate fuel assemblies would be evaluated using the standard in-rack geometry, as necessary, for comparison to this limit. This limit is based on the limiting fuel lattices from the licensee's NCS analyses. The following section contains the technical evaluation of the NCS analyses supporting this change.

Technical Evaluation

There is no comprehensive, NRC-approved generic methodology for performing NCS analyses for fuel storage and handling. The methods used for the NCS analysis for fuel in the Browns Ferry SFP are described in AREVA safety analysis report ANP-3160 (Reference 3). The computer code benchmarking analyses supporting use of SCALE 4.4a for this application are described in the licensee's letter dated December 15, 2015 (Reference 3). Additional information describing the methods used is provided in the RAI responses attached to the licensee's letters dated February 16, 2016 (Reference 6), March 3, 2016 (Reference 7), and July 27, 2016 (Reference 27). No previously approved precedents exist that establish a technical basis for NRC-approved application of this analysis methodology to the Browns Ferry SFPs, so a complete review and evaluation was performed. Several SFP analysis deficiencies were identified during the review, but as will be discussed below, sufficient margin is built into the analysis methodology to offset the deficiencies for existing fuel. Consequently, the methodology is specific to this analysis and, without further revision, is not appropriate for other applications. This is acceptable for the limiting fuel lattices that bound all fuel currently stored in the SFP, but the findings of this safety evaluation do not generically extend to fuel that is not bounded by this NCS analysis.

Computational Methods

Code Versions and Applications

For the criticality calculation, the licensee used the KENO V.a, BONAMI-2, and NITAWL modules and the CSAS25 driver in the SCALE 4.4a code package, with 44 energy group cross-section data based on the Evaluated Nuclear Data File, Version 5 (ENDF/B-V) neutron cross section library. SCALE is a state-of-the-art Monte Carlo criticality code developed and maintained by Oak Ridge National Laboratory (ORNL) for use in performing reactor physics and criticality safety analyses for nuclear facilities and transportation/storage packages. The code and its accompanying nuclear data sets have been extensively validated by ORNL for various neutron transport calculations, including criticality calculations. Therefore, the NRC staff finds the underlying neutron transport methodology to be acceptable, but the code needs to be validated for specific applications. The NRC staff review of the licensee's validation of SCALE for its SFP NCS application is discussed below, in the Computer Code Validation section.

For the depletion calculation to determine the spent fuel isotopic compositions, the licensee used the two-dimensional (2-D) CASMO-4 computer code with a 70-group cross-section library mainly derived from the ENDF/B-IV neutron cross section library. In some cases, the ENDF data has been supplemented by other data sources. CASMO-4 has been approved by the NRC for core physics calculations at Browns Ferry as part of the AREVA core design methodology, as per Section 3.6 of the Browns Ferry UFSAR. The CASMO-4 code and associated cross section libraries are controlled by AREVA procedures to meet the requirements of the AREVA core physics methodologies as approved by the NRC. These computer codes, and the nuclear data sets with them, have been used in many NCS analyses and are industry standards.

Consistent with the NRC's Guidance in DSS-ISG-2010-01 (Reference 232), typical NCS analyses must include uncertainties to cover the lack of validation of spent fuel compositions (Reference 232), the lack of validation for k-effective calculations of burned fuel systems containing minor actinides and fission products, and the use of any other short lived, volatile, and gaseous isotopes that are being modeled in the analyses. In ANP-3160 (Enclosures 1 and 2 to letter dated December 15, 2015 (Reference 3)) AREVA utilized a reactivity equivalent beginning-of-life (REBOL) lattice to perform the SCALE 4.4a calculations. Consequently, isotopes produced as a result of depletion are not included in the calculation. However, the REBOL lattices are determined based on reference bounding lattices depleted using CASMO-4 to the burnup of maximum reactivity. In order to address the uncertainties for the CASMO-4 based data, the REBOL lattices were specified so that their reactivities were at least 0.01 reactivity adder (Δk) greater than the maximum reactivities of the reference lattices. The NRC staff evaluated the validation of this approach provided in Appendix D of ANP-3160 (*Burnup Uncertainty* section) and determined that a 0.01 Δk increase in reactivity is sufficient to bound any depletion related uncertainties. As a result, no additional uncertainties needed to be applied to the calculated values from SCALE 4.4a.

For all SCALE 4.4a calculations, the licensee used reasonable values for the following calculational parameters: number of histories per cycle, number of cycles skipped before averaging, total number of cycles, and the initial source distribution. More importantly, the licensee confirmed that all calculations converged by examining the plotted eigenvalue histories to verify that the average k-effective result is stable. The reasonableness of the parameters was judged based on a combination of general guidance provided in the supporting documentation for the SCALE code system and engineering judgement.

Based on the pedigree of the computer codes and the methodology used by the licensee to address known uncertainties, the computational methods implicit in the codes used for the NCS analyses are acceptable.

Computer Code Validation

The purpose of the criticality code validation is to ensure that appropriate code bias and bias uncertainty are determined for use in the criticality calculation. The ISG DSS-ISG-2010-01 references NUREG/CR-6698, "Guide for Validation of Nuclear Criticality Safety Calculational Methodology" (Reference 233).

NUREG/CR-6698 states, in part, that:

> In general, the critical experiments selected for inclusion in the validation must be representative of the types of materials, conditions, and operating parameters found in the actual operations to be modeled using the calculational method. A sufficient number of experiments with varying experimental parameters should be selected for inclusion in the validation to ensure as wide an area of applicability as feasible and statistically significant results.

The NRC staff used NUREG/CR-6698 as guidance for review of the code validation methodology presented in the application. The basic elements of validation are outlined in NUREG/CR-6698, including identification of operating conditions and parameter ranges to be validated, selection of critical benchmarks, modeling of benchmarks, statistical analysis of results, and determination of the area of applicability.

In ANP-3160 (Enclosures 1 and 2 to letter dated December 15, 2015 (Reference 3)), the licensee performed the validation of SCALE 4.4a by comparing calculated k-effective values with several different sets of critical configurations. A total of 68 critical configurations were included. The licensee used the International Handbook of Evaluated Criticality Safety Benchmark Experiments (IHECSBE) (Reference 234) to select appropriate critical benchmarks. The IHECSBE was prepared by a working group comprised of experienced criticality safety personnel from many countries. The handbook contains criticality safety benchmark specifications that have been derived from experiments that were performed at various nuclear critical facilities around the world. The benchmark specifications are intended for use by criticality safety engineers to validate calculational techniques used to establish minimum subcritical margins for operations with fissile material. Therefore, the NRC staff considers it an appropriate source of information for the critical experiment models, because it represents a consensus reference within the international criticality safety community for code benchmarks.

The licensee determined that it would be appropriate to treat all experiments as a single set, and found that the data were normally distributed. As a result, a parametric analysis was performed to identify the lower tolerance limit. However, the SFP configuration being analyzed primarily consists of fuel assemblies surrounded by plates containing B-10, which is a strong neutron absorber. Twenty four of the sixty eight critical configurations have a similar configuration, while the remainder have either weak neutron absorbing materials or nothing but water between the fuel rod clusters. As a result, these 24 critical configurations should be evaluated as a group to verify that they do not result in a more limiting bias or uncertainty. The

NRC staff examined the data from the group of 24 critical configurations with strong neutron absorbers and determined that analysis of this set, without the other 44 critical configurations, may change some of the observed trends significantly. A visual review of this data revealed that the changes would be such that the overall limiting k-effective value based on the lower tolerance bands from the trending analysis would be expected to be higher (i.e., less limiting) for the reduced data set. Therefore, the trend corrected bias and uncertainty values calculated using the full set of 68 critical experiments is conservative and acceptable.

The ISG document for SFP NCS analyses, DSS-ISG-2010-01 (Reference 232), states in Item IV.4.a.i that the critical experiments previously evaluated by the NRC in NUREG/CR-6979, "Evaluation of the French Haut Taux de Combustion (HTC) Critical Experiment Data," (Reference 235) should be considered as part of the validation. The use of the HTC experiments is important to cover the actinide distribution of burned fuel, as well as to evaluate the criticality implications of different storage arrangements for burned fuel. Since the licensee utilized a beginning of life (BOL) reactivity equivalent methodology where the NCS analyses do not include plutonium or other actinides, this item is not applicable. However, the licensee did include an addendum to Appendix C of ANP-3160 (Enclosures 1 and 2 to letter dated December 15, 2015 (Reference 3))that demonstrates that inclusion of HTC experiments similar to BWR SFP conditions will not result in a higher (and, therefore, more conservative) bias or uncertainty. Therefore, use of the 68-case data set that excludes HTC experiments is acceptable.

The licensee identified the applicable operating conditions for the validation (e.g., fuel assembly materials and geometry, enrichment of fissile isotope, fuel density, types of neutron absorbers, moderators and reflectors, rack material, and physical configurations). The licensee compared the spectral parameters (e.g., EALF, fuel/moderator ratio) between the benchmarks and the Browns Ferry SFP conditions to demonstrate that the selected benchmarks are applicable.

Based on the NRC staff's review of the validation database and its applicability to the compositions, geometries, and methodologies used in the licensee's NCS analyses, the code validation was found to be acceptable and all identified biases and uncertainties were propagated appropriately.

SFP and Fuel Storage Racks

<u>SFP Water Temperature</u>

The licensee treated the SFP water temperature in a bounding manner. The design basis calculations were run using the minimum SFP temperature, and follow-up calculations were performed to verify that higher SFP temperatures (up to the maximum) did not result in a higher k-effective value. The NRC staff finds the licensee's approach to be acceptable, and that the results were bounded by the limiting k-effective values.

SFP Storage Rack Modeling

Browns Ferry has multiple rack modules with two different sizes in the SFP, with water gaps between adjacent racks. In the criticality analysis, the licensee chose to use a bounding approach in which the most reactive fuel assembly lattices (i.e., two that represent the top and bottom of the ATRIUM 10XM fuel assembly design) are identified as the design basis lattices. REBOL lattices are then developed based on the maximum reactivity of design basis lattices at

their limiting exposure. The SFP is then assumed to be fully loaded with fuel assemblies using the REBOL lattices. A series of SCALE calculations were performed to evaluate the relative reactivity of different modeling approaches for the fuel racks: a single-cell infinite array approximation, an explicit 2x2 infinite array, a 2x2 infinite array that only models the Boron-10 (B-10) in Boral (no other structural materials), and several different full rack models with nominal rack spacing. The 2x2 infinite array that only models the B-10 in Boral was selected for use in the final criticality calculations (except where an expanded geometry was needed to evaluate accident conditions). The licensee demonstrated that only modeling the B-10 in the Boral (neglecting the aluminum and carbon) and using an infinite 2x2 array instead of an actual rack module array size (13x13 or 13x17) was conservative by about 0.003 and 0.009 Δk, respectively. The licensee also included a more explicit modeling of the upper and lower axial boundary conditions using conservative reflector materials, which demonstrated a small additional conservatism. The NRC staff did not fully evaluate the modeling assumptions associated with this calculation due to the minor nature of the reactivity impact and the fact that this modeling was not used in the base NCS analyses. The single-cell, infinite array model yielded slightly more conservative results, but the reactivity difference was minor. CASMO-4 is not capable of modeling more complicated geometries than a single-cell infinite array, so the main purpose of this calculation was to demonstrate that the modeling simplifications necessary to model the SFP configuration in CASMO-4 would not have a significant impact on the calculated k-infinity.

In the criticality analysis, the normal condition is assumed to be one in which there are no missing Boral plates. The original re-racking license amendment request (approved in (Reference 236)) stated that in-situ testing would be performed to verify the presence of Boral plates in all SFP storage tubes. However, the acceptance criteria allowed for up to four missing plates, which was incorporated into the SFP criticality analyses at the time. The current SFP criticality analysis only assumes a single missing Boral plate as part of postulated accident conditions, so the NRC staff requested more information regarding the licensee's verification that there were no missing Boral plates. The licensee reviewed its permanent records and determined that a number of records associated with the aforementioned testing were missing (refer to the licensee's letters dated March 8, 2016 (Reference 7) and July 27, 2016 (Reference 27). However, based on available documentation, the licensee was able to establish that the testing was successful for all SFP storage tubes except for a total of 162 tubes (corresponding to 648 Boral plates) in six rack modules (one installed in the Unit 3 SFP and five in the Unit 1 SFP). Inspection of the records for the testing in the Unit 3 SFP strongly suggest that the neutron detectors became saturated due to gamma radiation from nearby irradiated fuel, which resulted in significant reductions in total neutron counts compared to other tests. Since the total neutron counts were much lower than expected, this would not be interpreted as a "failure" to detect the neutron attenuation of the Boral plates. This could not be explicitly verified for the Unit 1 SFP racks, but other documentation from the time (i.e., work plans, NRC correspondence) indicate that the licensee and the NRC at the time both believed that the inconclusive testing was attributable to the presence of irradiated fuel as discussed in the licensee's letters dated March 8, 2016 (Reference 7), and July 27, 2016 (Reference 27), and the NRC's inspection report dated July 13, 1983 (Reference 237).

In 1983, when the NRC identified the inconclusive testing as part of a safety inspection, the licensee justified the acceptability of the Boral installation in the SFP racks by: (1) providing copies of the quality assurance records generated as part of the manufacturing process that verify the correct Boral content in the racks, and (2) providing a statistical analysis performed by the vendor to determine the statistical likelihood of missing Boral plates among the cells for

which the results are inconclusive. The NRC inspection report documentation (Reference 237) at the time confirmed the acceptability of the information provided by the licensee, but the staff needed to verify that the finding was still applicable to a NCS analysis that assumed fewer missing panels. Therefore, the staff asked for more information on the statistical analysis and supporting documentation.

The licensee explained in its letter dated July 27, 2016 (Reference 27), that the statistical analysis was based on typical manufacturing process analyses to determine the probability of failures in an unknown sample, given a known failure rate. The licensee stated, in its letter dated March 3, 2017 (Reference 41), that it was able to locate additional records verifying traceability of individual Boral plates to specific locations in the SFP racks via documentation of the serial numbers associated with the Boral plates installed in each square tube used to construct the SFP racks. This provides an alternative verification of whether a Boral plate was installed in each appropriate location in the SFP racks. After combining both sets of verification records, a total of 172 out of 20,940 Boral plates could not be verified to have been installed in the Browns Ferry SFP racks.

Since the manufacturing process meets the criteria to make statistically meaningful inferences from a binominal distribution, the licensee used such a distribution to demonstrate that a 95 percent confidence exists at a 95 percent probability that all Boral plates were installed. The licensee used the equations in NUREG/CR-1475, Revision 1 (Reference 238) to determine an upper confidence limit for a population for which no defects have been identified by testing a defined sample within that population. This is a reasonable approach, given that the NRC staff has previously accepted the justification that the inconclusive testing results are as a result of interference from the presence of irradiated fuel nearby. This rules out the possibility that the inconclusive testing results are correlated with the probability that the Boral plates are missing. Therefore, the licensee has provided adequate justification to support the assumption in the NCS analysis that no Boral plates are missing in the SFP racks.

An important parameter for criticality in the racks is the B-10 areal density of the Boral neutron-absorbing material. The licensee's NCS analysis used 0.013 g/cm^2 as the areal density of the Boral plates, which is the minimum design areal density, so this represents a bounding approach. The licensee did not describe how the distribution of as-built areal densities compares to this minimum value. Further information was provided in the licensee's letter dated March 3, 2017 (Reference 41), which included the as-built areal density distribution for 88.08 percent of the plates installed at Browns Ferry. If most of the plates are at or near the minimum design value, then statistically, the percentage of plates below the minimum design areal density may approach 5 percent. If the plates are not randomly distributed in the SFP, then the minimum design areal density criteria may not be satisfied at a local level in the SFP. However, the information provided by the licensee provides reasonable assurance that no panels are below the minimum design areal density criterion, given the fact that the panels for which the areal densities are unknown were manufactured using the same process, and the large margin between the lowest as-built areal density and the minimum certified area density.

Boral consists of discrete boron carbide particles suspended in an aluminum matrix, so the potential exists for reduced neutron-absorbing efficiency due to self-shielding and neutron streaming effects. The licensee discusses this effect and states that the isotropic neutron flux in the SFP environment minimizes the reactivity impact of these effects, therefore, the effect was not explicitly evaluated. Recent studies show that there is some reduction in the neutron absorption effectiveness of this type of material compared to a homogeneous mixture with the

same B-10 areal density for SFP criticality calculations. This effect is generally on the order of 0.002-0.003 Δk for B-10 areal densities near 0.02 g/cm^2 and boron carbide particle sizes comparable to that found in typical Boral (~100 μm). These parameters are close enough to the Boral material utilized at Browns Ferry to use 0.003 Δk as a reasonable estimate of the potential non-conservatism for not explicitly treating the heterogeneity in the Boral core.

Boral has a known history of blistering due to exposure to the SFP environment, as discussed in Information Notice 2009-26 (Reference 239). In order to account for the reactivity impact due to the displacement of moderator between SFP rack cells and the resulting reduction in the neutron absorption efficiency of the Boral plates, the licensee performed a calculation that incorporated a uniform 0.055 inch void region added to the modeled Boral thickness. The calculated reactivity increase was applied as a bias in the final k-effective calculation. This approach is acceptable because it conservatively bounds the results from the coupon surveillance performed at Browns Ferry as well as information provided elsewhere for the largest typical blister size (see AAR Topical Report 1829 (Reference 240)) and blister quantity (see EPRI TR-1025204 (Reference 241)). Any indication that Boral blistering at Browns Ferry is not bounded by this modeling would be expected to be identified as part of the licensee's Boral surveillance program and addressed via its corrective action program.

The licensee's treatment of the B-10 neutron absorbing material in the Boral plates was found to be generally acceptable, but the NRC staff identified some potential non-conservatisms that can be offset by available margin to the regulatory limit. The NRC staff evaluated other relevant aspects of the storage rack modeling and found them to be modeled conservatively or using appropriate parameters with the uncertainties addressed, as discussed in this section of the SE under the "Fuel Assembly and Storage Rack Manufacturing Tolerances and Uncertainties" heading. As a result, the storage rack modeling is acceptable.

Bounding Fuel Assembly Design

ANP-3160 (Enclosures 1 and 2 to (Reference 3)) explains that a reference ATRIUM 10XM fuel assembly design was used that bounds all fuel currently stored in the Browns Ferry SFPs and that is planned for use at Browns Ferry. This fuel assembly is based on two different fuel lattices, one representing the bottom part of the fuel assembly that contains part length fuel rods, and the other representing the upper part of the fuel assembly (with water replacing the fuel rods in the part length fuel rod locations). Reactivity equivalent beginning of life (REBOL) lattices were developed that are essentially gadolinia-free fresh fuel lattices with an uniform U-235 enrichment and a reactivity of at least 0.01 Δk greater than the aforementioned reference fuel lattices. The REBOL lattices were used to model the fuel assembly used in the final demonstration of compliance with the SFP subcriticality requirement. The NRC staff's review of the acceptability of the bounding fuel assembly design included an assessment of the licensee's demonstration that the reference fuel assembly will be bounding, as well as an evaluation of the REBOL methodology.

As-Manufactured Fuel Assemblies

Most of the older fuel stored in the Browns Ferry SFPs is dispositioned based on the fact that their initial peak average enrichment was less than 2.99 percent U-235, with one exception. The reasoning for screening out these fuel assemblies is that the REBOL lattices used in the final NCS analysis have an enrichment of 3.21 percent. In addition, the fuel stored in the Browns Ferry SFPs contain gadolinia while the REBOL lattices do not. The one exception, a

group of four lead test assemblies, was excluded from further calculation because there are only four fuel assemblies of this design, their enrichment, while above 2.99 percent, was still below that of the REBOL lattices, and they contain gadolinia. The REBOL lattices are evaluated at BOL, while most typical fuel lattices will reach peak reactivity after some burnup accumulation, which will deplete the U-235 enrichment and result in a lower peak reactivity than a gadolinia-free, BOL lattice of similar initial U-235 enrichment. Therefore, the NRC staff finds the reasoning behind excluding these fuel assembly designs from further analysis to be appropriate, with conservative screening criteria applied.

Using CASMO-4, the licensee analyzed all of the fuel lattices which did not meet the criteria described in the prior paragraph to demonstrate that they were bounded by the reference lattices used to develop the REBOL lattices. The CASMO-4 depletion calculations were performed at different void fractions to capture the dominant impact of core depletion on the reactivity characteristics of the lattice. Other operating parameters may have some impact, but as discussed in the *Burnup History/Core Operating Parameters* section, these impacts are minor. The resulting compositions were then imported into a CASMO-4 in-rack k-infinity calculation for comparison to the in-rack k-infinity of the reference lattices. The results also show that a sufficiently large reactivity margin exists between the most limiting non ATRIUM 10XM fuel lattice and the most limiting ATRIUM 10XM fuel lattice. As a result, any variation in the total uncertainty due to manufacturing tolerances of non-ATRIUM 10XM fuel assembly designs would not result in the potential for a k_{eff} value, including uncertainties, that exceeds the calculated k_{eff} from the final NCS analysis.

A major difference between the licensee's treatment of the as-manufactured fuel assemblies and the reference fuel assembly is that the Blended Low Enriched Uranium (BLEU) fuel assemblies are modeled as BLEU fuel, with the appropriate U-234 and U-236 weight percentages. The reference fuel assembly is modeled using commercial grade uranium (CGU), with no U-234 or U-236. CGU lattices will be more reactive than BLEU lattices at the same U-235 enrichment due to the strong absorption cross section of the U-234 and U-236 isotopes. The isotopes are present and the licensee was able to model the as-manufactured specifications for each fuel lattice. However, there are uncertainties associated with these isotopes and their treatment during depletion. The most limiting BLEU fuel lattice has 0.0277 Δk of available margin to the reference ATRIUM 10XM fuel lattice, which is significantly larger than the expected magnitude of any U-234/U-236 related burnup uncertainties; therefore, the ATRIUM 10XM fuel lattices remained bounding.

Some of the fuel in the Browns Ferry SFP has been modified from its original as-manufactured condition. The following modifications affect at least one fuel assembly stored in the Browns Ferry SFPs: (1) broken fuel rod(s); (2) fuel rod(s) replaced with stainless steel rod(s); and (3) fuel rod(s) replaced with other fuel rods of similar reactivity from other fuel assemblies. In cases where a fuel rod broke, the rod continues to be maintained in its location in the fuel assembly, so the change in geometry and composition is not significant. The fuel assemblies with fuel rods replaced with other fuel rods of similar reactivity have a maximum planar enrichment of 3.08 percent U-235, and are all well past their peak reactivity burnup. Therefore, their reactivities are bounded by the REBOL lattices. Finally, the fuel assemblies for which stainless steel rods were used as a replacement for fuel rods preserves the amount of moderator while removing fissile material. In addition, stainless steel has some neutron capture properties, so the result of replacing a fuel rod with a stainless steel rod of the same dimensions would be expected to yield a net reduction in reactivity. Since none of the modifications replace a fuel rod with one of significantly higher reactivity or a water hole, the described modifications

to fuel assemblies in the Browns Ferry SFPs can be expected to either have no impact on reactivity, or reduce the reactivity, and are therefore acceptable.

As a result of the licensee's analysis and dispositioning of the as-manufactured fuel currently located at Browns Ferry, the NRC staff finds that the reference fuel assembly design bounds all fuel currently stored in the Browns Ferry SFPs.

Future Fuel Assemblies

Table 2.1 of ANP-3160 (Enclosures 1 and 2 to (Reference 3)) provides specific criteria to use in qualifying future ATRIUM 10XM fuel assemblies for storage in the Browns Ferry SFPs. Since the Browns Ferry UFSAR references this document as the licensing basis for SFP storage, the criteria must ensure that any fuel that satisfies the criteria, will also be bounded by the NCS analysis in ANP-3160. The ATRIUM 10XM fuel configuration, SFP rack configuration, and fuel channel configurations as evaluated in the NCS analysis are explicitly defined as part of the limitations on qualifying new ATRIUM 10XM fuel. There are two options provided to demonstrate that the reactivity of any fuel lattices in fuel intended for SFP storage will be bounded by the reference fuel lattices used in this NCS analysis: (1) meet maximum/minimum requirements for U-235 enrichment, number of gadolinia (Gadolinia) rods, and Gadolinia concentration; or (2) meet a maximum k-infinity limit based on in-rack CASMO-4 calculations.

The fuel rod enrichment patterns used in BWR fuel are developed to flatten the power distribution in order to avoid large spikes in rod power that could create problems with meeting thermal limit requirements. In practice, this means placing lower-enrichment fuel rods in the fuel lattice locations that are near significant quantities of moderator (i.e., the corners/edges of the lattice as well as the rods surrounding the internal water channel). The REBOL lattices assume a uniform U-235 enrichment distribution, which would result in higher than typical U-235 enrichments in the aforementioned locations. The licensee stated that studies showed that a uniform enrichment distribution was determined to be more conservative than a more representative lattice design by 0.002 to 0.004 Δk. This is consistent with the staff's experience with similar studies. Therefore, the REBOL lattices would be expected to bound localized reactivity impacts due to the U-235 enrichment distribution in the fuel lattice. With that in consideration, an upper limit on average U-235 enrichment and lower limit on Gadolinia concentration based on the reference fuel lattices will help ensure that the reactivity of the reference fuel lattices remains bounding.

A lower bound on the number of Gadolinia rods is also necessary, but the location of the Gadolinia rods can have an impact on peak reactivity due to variations in Gadolinia burnout. The licensee stated that the Gadolinia rods in the reference fuel lattices were placed in limiting locations, but no further explanation was given. A review of the CASMO-4 inputs provided in Appendix A of ANP-3160 (Enclosures 1 and 2 to letter dated December 15, 2015 (Reference 3)) showed that the Gadolinia rods are strategically placed in locations that maximize their proximity to highly moderated regions in the top lattice, when considering that the licensee's acceptance criteria for SFP storage prohibit placement of Gadolinia rods on the periphery or adjacent to the internal water channel. The licensee's calculations showed that lower void fractions are limiting for the reference fuel lattices, which implies that for the ATRIUM 10XM fuel lattice, higher moderation that leads to a more rapid burnout of Gadolinia will result in a more limiting peak reactivity. Therefore, the locations of the Gadolinia rods in the reference fuel lattices are appropriate to reasonably bound the allowed variations in placement of Gadolinia rods.

The second option for qualifying fuel lattices is a straightforward in-rack k-infinity calculation using CASMO-4 to confirm that the lattices are not more reactive than the values calculated for the reference fuel lattices. This calculation would include as-built gadolinium and uranium loadings for the fuel lattices of interest. This criteria, in effect, allows the licensee to evaluate new fuel assemblies in a manner similar to the previously manufactured fuel (discussed in the "Future Fuel Assemblies" section).

The licensee chose to conservatively treat BLEU fuel as CGU fuel. The licensee provided data that demonstrated that BLEU fuel has a lower peak reactivity than CGU fuel for the same U-235 enrichment, by almost 0.01 Δk. As a result, the licensee did not need to address uncertainties in the U-234 and U-236 number densities in the BLEU fuel, since they were conservatively assumed to not be present. The criteria do not make it clear that the in-rack k-infinity calculation should treat the BLEU fuel as CGU fuel. Since the calculations in Appendix B to evaluate fuel currently stored in the Browns Ferry SFPs include modeling of the U-234 and U-236 isotopes in BLEU fuel, some ambiguity exists on whether it is acceptable to model the BLEU fuel as such for the purpose of qualifying new fuel. When asked, the licensee stated that the intent was to allow BLEU fuel to be explicitly modeled if necessary. In order to support this proposed practice, the licensee supplied information in its letter dated July 27, 2016 (Reference 27) **[[**

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An additional consideration in the qualification of future fuel lattices based on k-infinities calculated by CASMO-4 in any bias or uncertainty in the CASMO-calculated k-infinity values relative to SCALE 4.4a. In order to address this issue, the licensee provided an analysis in Appendix D of ANP-3160 supporting the use of CASMO-4 in this manner. In essence, the licensee performed 11 calculations with both CASMO-4 and SCALE 4.4a for each of the following product lines: GE 8x8, GE 9x9, GE 10x10, ATRIUM-10, and ATRIUM 10XM. Where applicable, both top and bottom lattices were analyzed. For each lattice, the U-235 enrichment was varied in 0.05 weight percent U-235 increments between 3.1 weight percent and 3.6 weight percent. Since the enrichment and fuel lattice geometry are the only factors that vary for a REBOL calculation for the Browns Ferry SFPs, this approach adequately covers the area of applicability near the limiting reactivity as defined by the enrichment of the reference lattices.

A code-to-code comparison was then performed using an analysis methodology similar to the code validation approach in NUREG/CR-6698 (Reference 233), using the SCALE 4.4a results in lieu of critical experiments. The resulting bias and uncertainty was used to demonstrate that the 0.01 Δk increase in reactivity for the REBOL lattice relative to the k-infinity limit is satisfactory to bound CASMO-4 uncertainties relative to SCALE 4.4a in addition to the depletion uncertainty. The licensee considered all calculations as a single data set in performing their validation, which may obscure geometry-specific reactivity effects or trends. The NRC staff examined the data calculated for each lattice type and determined the following: (1) there was no clear trend in reactivity differences as a function of enrichment for any lattice; (2) the reactivity differences calculated for the ATRIUM 10XM lattice, analyzed in isolation, would yield a similar bias and a smaller uncertainty, with any differences readily accommodated by the 0.01 Δk adder; and (3) any increase in bias or uncertainty that might occur from examining other lattices in isolation is within the extra margin inherent in the lower reactivity of the legacy fuel relative to the design

basis ATRIUM 10XM fuel lattices. Therefore, the use of CASMO-4 to evaluate new ATRIUM 10XM fuel assemblies, based on the in-rack k-infinity described in Table 2.1, is acceptable.

As a result of the above discussion on how the criteria provided by the licensee in Table 2.1 of ANP-3160 ensure that any fuel qualified using this criteria is bounded by the reference fuel lattices used in this NCS analysis, the NRC staff finds the stated limitations to be acceptable for qualifying future ATRIUM 10XM fuel assemblies for storage in the Browns Ferry SFPs.

REBOL Fuel Assembly Modeling

The final fuel assembly used in the demonstration of compliance with the SFP subcriticality requirement is a simple fuel assembly composed of two REBOL lattices (top and bottom). The REBOL lattices are based on the limiting fuel lattices for a reference fuel assembly that was established to bound all fuel currently stored in the SFP and all ATRIUM 10XM fuel expected for use at Browns Ferry. Several conservative simplifications were incorporated, some of which have previously been discussed. The top lattice conservatively bounds the "plenum" region of the fuel, where the part length rod locations are occupied by the top plenum and plenum spring for the part length rods. In Appendix B of ANP-3160 (Enclosures 1 and 2 to (Reference 3)), the licensee stated that the ATRIUM 10XM lattice is under-moderated in the SFP environment. This is consistent with the fact that the limiting top lattice achieves the same in-rack k-infinity as the limiting bottom lattice despite having less total U-235 in the lattice. Therefore, modeling this region as water instead of explicitly modeling the plenum is conservative. Periodic boundary conditions are applied in the axial direction, which is also conservative because any neutrons escaping from the upper and bottom boundaries of the active fuel would mainly be lost to leakage. Periodic boundary conditions were also applied to the x-y plane for a 2x2 explicit Boral rack model as discussed in Section 3.8.6.2 of this SE under the SFP Storage Rack Modeling heading.

The main distinction of the REBOL methodology is the fact that the REBOL fuel lattices are modeled as no-Gadolinia lattices with no burnup that have a calculated reactivity of at least 0.01 Δk greater than the peak reactivity for the reference fuel lattices. The 0.01 Δk "reactivity adder" is intended to cover CASMO k-infinity evaluation and depletion related issues not explicitly addressed in the NCS analysis (discussed in Section 3.8.6.2 of this SE under the Future Fuel Assemblies heading). NUREG/CR-6683 (Reference 242) performed an evaluation of reactivity equivalencing methodologies in use for PWR SFP NCS analyses at the time. BWR SFP NCS analyses were not a focus of the NRC staff review, but the general trends shown in the NUREG should be applicable. NUREG/CR-6683 found that the practice of equating the reactivity of spent fuel to fresh fuel is acceptable, provided that the SFP conditions for which the reactivity is determined remain unchanged. For PWRs, non-conservatisms were identified for scenarios that do not apply to the Browns Ferry SFPs, which do not utilize soluble boron or store fuel in defined loading patterns. However, the use of the REBOL lattices to analyze accident conditions do represent a deviation in the SFP configuration for which the REBOL lattices were determined.

The accident conditions analyzed by the licensee represent SFP configurations where: (1) poison material was removed, (2) fuel is placed in a geometry different from the one used to determine the REBOL lattice, or (3) the SFP temperature is different from the temperature used to determine the REBOL lattice.

The first scenario is no longer necessary to support a finding of regulatory compliance, due to additional information submitted by TVA (discussed in Section 2.8.6.2 of this SE under the SFP Storage Rack Modeling heading) which demonstrates that there is a 95 percent probability, with a 95 percent confidence, that no Boral plates are missing.

Several different accident configurations were analyzed that address geometries different from the infinite single-cell model used to determine the reactivity of the REBOL lattice. NUREG/CR-6683 explains that the non-conservatism that may arise from analyzing different checkerboarded SFP configurations arises from the fact that the distribution of the fission products and minor actinides may result in a different relative reactivity worth that is not captured by a REBOL lattice. The misplaced fuel assembly scenarios are, in general, similar to a configuration where multiple cells of an infinite array are replaced with empty cells. NUREG/CR-6683 showed that analysis of a configuration where a fresh fuel equivalent lattice is in a configuration with less reactive cells than those used to determine the fresh fuel equivalent lattice is conservative. Therefore, the analysis of the misplaced fuel assembly scenarios is likely to be conservative. The analysis of a scenario where Boral storage racks are forced together also includes a different geometry, but the reference fuel assemblies are all the same. Therefore, the only potential impact on the reactivity worth of the fission products and minor actinides would be due to the change in the energy spectrum for neutrons communicating across the gap between the peripheral cells of adjacent rack modules. The lack of Boral plates between alternating pairs of face adjacent peripheral fuel assemblies and the water gap between rack modules would have the net effect of softening the neutron spectrum. This should not be a large enough effect to have a significant reactivity impact, but if there is one, it would be an increase in the relative negative reactivity worth for the spent fuel lattice. Since the REBOL lattice will effectively result in an equivalent or lower relative reactivity worth credit for the fission products and actinides relative to an explicit modeling of the spent fuel lattice, the REBOL approach is acceptable for the licensee's analysis of misplaced fuel assembly configurations and a reduction in the gap between rack modules. Finally, an increase in SFP temperature is bounded by the fact that the reference fuel assembly (and resulting REBOL lattices) were evaluated at their limiting SFP temperature of 4 °C.

The selection and modeling of the REBOL fuel lattice used in the NCS analyses was extensively inspected by the staff, and found to be acceptable for the purpose of this analysis. As discussed in this section, there are known issues with reactivity equivalencing methodologies when the SFP configuration being analyzed is different from the SFP configuration that the fresh fuel equivalent lattices were determined for. However, each such situation was considered on a case by case basis and reasonable assurance exists that the REBOL approach will result in equivalent or conservative results.

Fuel Assembly Manufacturing Tolerances and Uncertainties

The manufacturing tolerances of the storage racks and fuel assemblies contribute to SFP reactivity. DSS-ISG-2010-01 (Reference 232) does not explicitly discuss the approach to be used in determining manufacturing tolerances, but past practice has been consistent with the Kopp Memo (Reference 231) that determination of the maximum k_{eff} should consider either: (1) a worst-case combination with mechanical and material conditions set to maximize k_{eff}, or (2) a sensitivity study of the reactivity effects of tolerance variations. If used, a sensitivity study should include all possible significant tolerance variations in the material and mechanical

specifications of the fuel and racks. The licensee chose to utilize the latter approach for the fuel assembly manufacturing tolerances.

The licensee's evaluation of the tolerance variations included the following components: fuel enrichment, gadolinia loading, fuel pellet density, fuel pellet void volume, gadolinia pellet density, fuel pellet outer diameter, fuel cladding outer diameter, fuel pin pitch, channel thickness, and channel growth. Most calculations were performed using the 2x2 infinite array REBOL model in SCALE, which combined the most limiting design basis lattice with the limiting SFP water temperature and minimum rack insert B-10 areal density. The exception was the gadolinia related uncertainties, which were partially evaluated using CASMO-4 because the reactivity impact of changes to the gadolinia number densities include a depletion component. For each set of calculations associated with varying a specific parameter, the maximum reactivity increase was identified. If there was no reactivity increase, then the contribution of this manufacturing tolerance to the uncertainty was considered to be zero. These uncertainties were statistically combined with the other uncertainties, rounded up, and included in the final estimation of k_{eff}. This is consistent with past precedent for criticality analyses and with the guidance provided in the Kopp Memo, and thus is acceptable.

Revision 1 of ANP-3160 (Enclosures 1 and 2 to (Reference 3)), as submitted by the licensee, considered two changes to the fuel assembly geometry due to irradiation, fuel spacer growth and channel growth. The licensee stated that fuel rod geometry changes were not considered because pellet deformation with respect to burnup does not significantly change the neutronic characteristics of the fuel. In addition, the licensee treated the irradiation-caused geometry changes as part of the uncertainties calculated for the fuel manufacturing tolerances. The staff asked the licensee to provide further justification for this treatment, given that clad thinning due to creep can affect reactivity and irradiation-caused geometry changes are not distributed randomly around nominal manufacturing specifications.

The licensee re-evaluated the fuel geometry changes due to irradiation in its letter dated July 27, 2016 (Reference 27). Channel geometry changes as a result of irradiation were removed entirely, since the licensee explained that bowing or bulging would not change the amount of channel material, just move its spatial location slightly. Furthermore, there is already some conservatism inherent in the use of a uniform thickness for the channel at its maximum value, rather than explicitly modeling the partial thinning of the advanced 100 mil (0.100 inch) fuel channel used with the ATRIUM 10XM fuel. Significant geometry changes would not be expected at relatively low burnups for the temperature that the channels would be at from processes such as oxide formation, and the spatial location change in channel material would generally maintain the same radial amount of moderator displacement between adjacent fuel assemblies in the core. Therefore, the NRC staff accepts this justification for not including fuel channel growth among the potential geometry changes due to irradiation. The rest of the calculations were updated by the licensee to treat fuel spacer growth and cladding thinning as system biases, and demonstrated that there was no net change to the final k_{eff} rack-up for comparison to the regulatory limit.

The NRC staff evaluated the treatment of various fuel manufacturing tolerances and uncertainties, as well as geometry changes due to irradiation. All of the licensee's evaluations were found to be acceptable and in line with current guidance for SFP NCS analysis.

Spent Fuel Characterization

Characterization of fresh fuel is based primarily on uranium-235 enrichment, fuel rod gadolinia content and distribution, and various manufacturing tolerances. The manufacturing tolerances are typically manifested as uncertainties, as discussed above, or are bounded by values used in the analysis. These tolerances and bounding values would also carry through to the spent nuclear fuel, so common industry practice has been to treat the uncertainties as unaffected by the fuel depletion. The characterization of the isotopic number densities in the spent nuclear fuel is more problematic. Its characterization is based on the specifics of its initial conditions and its operational history in the reactor. That characterization has three main areas: a burnup uncertainty, the axial and radial apportionment of the burnup, and the core operation that achieved that burnup.

Burnup Uncertainty

The REBOL methodology does not perform the NCS analysis using burned fuel, so the isotopic number densities in the NCS analysis do not require an uncertainty. However, the enrichment of the REBOL lattices was based on the reactivity of reference fuel lattices depleted in CASMO-4, which do have an associated burnup uncertainty. Therefore, a burnup uncertainty still needed to be separately developed and applied in the NCS analysis. The licensee determined the burnup uncertainty in two different ways, as documented in Appendix D to ANP-3160 (Enclosures 1 and 2 to (Reference 3)).

The first approach that the licensee used was to derive the burnup uncertainty from the AREVA licensing topical report based on the benchmarking documented in EMF-2158 (Reference 214). For this benchmarking, AREVA compared CASMO-4 results against critical experiments performed by Studsvik and beginning of cycle cold critical data. The licensee obtained the standard deviation for CASMO-4 directly from Table 2.2 of EMF-2158, and applied a multiplier of 2 to obtain a 95/95 value for the burnup uncertainty, which is acceptable given the large number of cold criticals used in the evaluation. The majority, if not all, of the cold criticals evaluated for EMF-2158 were for cores which contained a significant amount of fuel burned beyond the point of peak reactivity. As such, the standard deviation for CASMO-4 when calculating cold criticals includes the variation in number densities as a result of depletion. However, it was not clear to the NRC staff how applicable this data would be to the ANP-3160 analysis because there was not sufficient data provided to determine if the fuel loaded in the part of the core driving the reactivity for each cold critical is adequately representative of the design basis lattices used in this analysis with respect to geometry and composition characteristics.

In the Kopp Memo, the NRC staff provided its recommended method for evaluating burnup uncertainty:

> [a] reactivity uncertainty due to uncertainty in the fuel depletion calculations should be developed and combined with other calculational uncertainties. In the absence of any other determination of the depletion uncertainty, an uncertainty equal to 5 percent of the reactivity decrement to the burnup of interest is an acceptable assumption.

The second approach used by the licensee to address the uncertainty in the burned fuel compositions is consistent with the above method. CASMO-4 was used to determine the

isotopic compositions for the bounding fuel lattices used to develop the REBOL lattices at zero and peak reactivity burnups, with the exception that no gadolinium was included in the models. SCALE calculations were performed to determine the difference in rack k-infinity as a result of the accumulated burnup with no gadolinium, and five percent of this reactivity difference was presented as an estimate for the depletion uncertainty.

The 0.01 Δk adder applied as part of their REBOL methodology bounds the reactivity increase that would result from statistically combining either estimate of the depletion uncertainty with the other uncertainties.

DSS-ISG-2010-01 guidance states that the uncertainty associated with any lumped fission products be evaluated. The licensee stated that while lumped fission products are used in CASMO-4 for depletion (and the impact on the other isotopic number densities relevant to reactivity would be captured through the burnup uncertainty), they are removed from the calculation used to determine the reactivity of the reference fuel lattices used to develop the REBOL lattices. This is conservative because removing credit for the lumped fission products means that the total neutron absorption cross section is reduced. In order for this approach to be appropriate, all fuel lattices qualified using the k-infinity limit (as discussed in the "Future Fuel Assemblies" section) would also have to be evaluated with the lumped fission products removed. [[

]]. The licensee's evaluation of the uncertainty in the fuel depletion calculations and the subsequent application is consistent with NRC guidelines, and therefore, is acceptable.

Axial Apportionment of the Burnup or Axial Burnup Profile

The standard BWR peak k-infinity analysis technique uses either 2-dimensional models or a 3-dimensional model with uniform axial burnup distributions. Generally, this is appropriate because the peak in limiting assembly reactivity occurs at lower burnups where the uniform axial burnup distribution is conservative. If one were to credit assembly burnup beyond the limiting peak reactivity burnup, at some assembly burnup value, the use of the uniform axial burnup would become non-conservative. At high burnups, the fuel near the top of the fuel assembly may have a significantly lower exposure than the overall average for the fuel assembly. Consequently, the local reactivity for these nodes may be higher than assumed in the criticality analyses based on a uniform burnup distribution. In the standard approach, the exposure at all axial elevations is assumed to be at a value which bounds the local reactivity for any other exposure, due to undepleted gadolinium or depletion of fissile material. The licensee chose to adopt the standard approach for dealing with the axial burnup distribution, which is acceptable.

Burnup History/Core Operating Parameters

The reactivity of light water reactor fuel varies with the conditions the fuel experiences in the reactor. This is particularly true for BWR fuel NCS analyses using the standard cold core geometry peak k-infinity analysis method. As a result of the usage of gadolinium in fuel rods, fuel assembly reactivity increases as the gadolinium isotopes are depleted. The value of the in-rack k_{eff} at peak reactivity is affected by the reactor depletion parameters in several ways.

Factors that lead to a more thermal neutron energy distribution cause the ^{155}Gadolinum, ^{157}Gadolinum and fission products to deplete more quickly, reducing plutonium generation. This causes the peak reactivity condition to be reached earlier, achieving a higher in-rack k_{eff} value. Increased water density and decreased void fraction lead to a more thermal neutron energy distribution and to lower fuel rod temperatures due to improved fuel rod cooling.

Factors that lead to a less thermal neutron energy distribution cause the ^{155}Gadolinum, ^{157}Gadolinum, and fission products to be depleted more slowly and result in increased plutonium generation and higher fuel rod temperatures. Decreased water density, increased void fraction, and control rod usage all result in neutron energy spectrum hardening.

DSS-ISG-2010-01 provides guidance that depletion simulations should be performed with parameters that maximize the reactivity of the depleted fuel assembly. DSS-ISG-2010-01 (Reference 232) references NUREG/CR-6665, "Review and Prioritization of Technical Issues Related to Burnup Credit for LWR Fuel," (Reference 243) which discusses the treatment of depletion parameters. For fuel and moderator temperatures, NUREG/CR-6665 (Reference 243) recommends using the maximum operating temperatures to maximize plutonium production. This recommendation is also applied to the moderator density for BWRs, but in practice, the high-void state is not always the limiting condition for peak reactivity analyses. The limiting lattice k-infinity value is established as the maximum value for a given fuel lattice under all possible operating conditions. The higher moderation that occurs in the no-void condition results in a more rapid depletion of the gadolinia, causing the k-infinity to peak earlier and higher. A lower moderator density results in a harder neutron spectrum and increased plutonium production, but this effect may not be large enough in BWRs to compete with the U-235 depletion that occurs prior to the later peak in k-infinity. The licensee evaluated the in-rack reactivity resulting from operation at different void fractions that cover the range of conditions that may be expected in the reactor core, and identified the limiting void fraction. For the top lattice in the reference fuel assembly design, the void fraction used was higher than the limiting value determined from a review of the data provided by the licensee. However, the reactivity difference is insignificant, so the choice of void fractions is acceptably limiting.

A specific recommendation for specific power and operating history is not addressed in NUREG-CR 6665. In NUREG/CR-6665, this effect is estimated to be about 0.002 Δk using operating histories it considered. Based on the difficulty of reproducing a bounding or even a representative power operating history, NUREG-CR-6665 merely recommends using a constant power level and retaining sufficient margin to cover the potential effect of a more limiting power history. The licensee chose to perform the design basis calculations at an average value for the power density, and performed calculations showing that a significant decrease in power density would result in a small reactivity increase. The final margin to the regulatory limit is sufficiently large to accommodate the estimated 0.002 Δk from NUREG/CR-6665, so the NRC staff does not consider it to be necessary to perform a more detailed sensitivity study or otherwise justify the treatment of the power density.

The licensee considered the impact of operation with control rod insertion as it affects the reactivity of the discharged assembly by establishing two broad bounding conditions: controlled operation and uncontrolled operation. The evaluation of the controlled operation scenario is a somewhat artificial situation, because it does not account for the reduction in power density resulting from insertion of the adjacent control blade. However, the change in power density is small compared to the reactivity impact of the harder neutron spectrum due to the presence of the control blade. As such, this approach is acceptable, especially since a fuel assembly would

be unlikely to be controlled during its entire depletion to peak reactivity. The results for the ATRIUM 10XM design basis lattice in Table 6.6 of ANP-3160 (Enclosures 1 and 2 to (Reference 3)) show that uncontrolled operation results in a more limiting peak in-rack reactivity.

Finally, the licensee performed calculations showing that a 100 °F change in fuel temperature for the depletion would result in no significant impact to reactivity. The studies were based on a nominal fuel temperature computed based on average linear heat generation rates, so this relatively modest change in fuel temperature does not bound the full range of possible operating conditions. However, the calculations are sufficient to show that the impact would be expected to be small, and certainly less than 0.001 Δk (estimate based on a rough extrapolation of the 100 °F results to an unrealistically high temperature increment).

The void fraction and the control rod position were treated in a bounding manner for the reference fuel lattice depletion. The power density and fuel temperature assumptions are potentially non-conservative, but the reactivity effect is bounded by available margin to the regulatory limit. The other core operating parameters have minimal impact on the in-rack reactivity of the reference fuel lattices. Therefore, the NRC staff finds the core operating conditions used to deplete the reference fuel lattices to be acceptable.

Integral Burnable Absorbers

As is typical for BWR plants, Browns Ferry utilizes gadolinia poison to help control reactivity and peaking within fuel assemblies. Since the NCS analysis is a REBOL analysis, no gadolinia is modeled in the final analysis. Section 2.8.6.2 of this SE under the "Future Fuel Assemblies" heading contains further discussion of the treatment of the gadolinia related requirements in the evaluation criteria for new fuel. Gadolinia is conservatively modeled for the depletion of the reference fuel lattices, and would be explicitly modeled in any evaluation of future ATRIUM 10XM fuel assemblies against the k-infinity limit. No other burnable absorbers are used.

The impact of gadolinium on the reactivity of the fuel is being treated explicitly by inclusion in all depleted fuel lattice models, and the manufacturing tolerances associated with the gadolinium is included in the licensee's final k_{eff} rack-up. Therefore, the staff finds that the licensee has appropriately considered the impact of integral burnable absorbers in the fuel.

Analysis of Abnormal Conditions

Section 7.6 of ANP-3160 (Enclosures 1 and 2 to (Reference 3)) presents the abnormal conditions considered in the analysis. The licensee considered the following abnormal conditions for a rack with no missing Boral plates:

- Missing Boral plate in the interior of the rack
- Boral storage racks being forced together
- Fuel assembly misplaced between SFP wall and storage rack
- Fuel assembly misplaced into the corner region adjacent to three racks
- Fuel assembly misplaced between the fuel preparation machine and storage rack
- Dropped assembly
- Loss of SFP cooling

Explicit calculations using the REBOL lattice were performed for the missing Boral plate, storage racks being forced together, and the various misplaced fuel assembly scenarios. Based on the information in the SFP Storage Rack Modeling section, in ANP-3160 (Enclosures 1 and 2 to (Reference 3)), the staff determined that assuming no missing Boral plate would be appropriate as part of the normal conditions. Given the installation configuration of the Boral plates, the staff is not aware of any credible accident conditions that would result in an already-installed Boral plate becoming loose and dropping out of the rack. Therefore, extra missing Boral plates do not need to be considered as a potential accident condition.

The licensee considered it to be unnecessary to perform calculations for the rest of the scenarios for the following reasons, which the staff considered to be appropriate technical justifications:

- Dropped fuel assembly – A vertical fuel assembly is bounded by the periodic axial boundary conditions in the NCS analysis, and a horizontal fuel assembly would rest on top of the SFP racks and be neutronically decoupled from the fuel stored in the rack cells (>12 inches of water between the dropped assembly and the top of the active fuel zone in the stored fuel).

- Loss of SFP cooling – the NCS analysis is done at the lowest temperature, which was found to be the limiting temperature for the Browns Ferry SFP configuration.

All considered accident scenarios have either been explicitly analyzed or are bounded by other accident conditions, therefore, the reactivity increase due to accident conditions is appropriately applied in the determination of the final k_{eff}.

Margin Analysis and Comparison with Remaining Uncertainties

Several potentially nonconservative assumptions were identified as part of the NRC staff's review of this LAR. A bounding estimate of the reactivity impact for each assumption is listed in the below table, based on NRC staff calculations or studies. In addition, any extra margins to the regulatory limit identified during the review of the NCS analysis are listed. Based on the below comparison, the NRC staff concludes that the available margins offset the potential nonconservatisms.

Potential Nonconservatisms	*Estimated Reactivity Impact (Δk)*
Modeling of BORAL as a homogeneous material	0.003
Nominal power density and fuel temperature during depletion	0.003
Total reactivity impact of nonconservatisms	0.006

Conservatisms	
Margin to regulatory limit	0.022
Modeling of Boral as B-10 only	0.003
Use of an infinite 2x2 array instead of a 13x13 model	0.009
Total reactivity impact of conservatisms	0.034

Summary

The NRC staff's review of the BFN Units 1, 2, and 3 spent fuel storage racks NCS analysis, documented in ANP-3160 (Enclosures 1 and 2 to (Reference 3)), identified some nonconservative items. Those items were evaluated against the margin to the regulatory limit and what the NRC staff considers an appropriate amount of margin attributable to conservatisms documented in the analyses. The identified conservatisms were sufficient to bound the nonconservative items, therefore, the NRC staff concludes that there is a reasonable assurance that the BFN Units 1, 2, and 3 SFP fuel storage racks meet the applicable NCS regulatory requirements. In addition, prevention of criticality, in conjunction with the administrative controls discussed in the Browns Ferry UFSAR Section 10.5.5 to limit the SFP decay heat load within the available capabilities of the SFP cooling systems, will ensure that an acceptably low temperature is maintained in the SFP.

Since the proposed TS 4.3.1.1.b limit is directly based on the base k-infinities for the limiting fuel lattices used in the NCS analysis, the proposed TS change supports regulatory compliance with NRC SFP subcriticality requirements. The NRC staff concludes that the spent fuel storage facilities will continue to meet the requirements of draft GDC-66 and 10 CFR 50.68 following implementation of the proposed EPU.

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 spent fuel pool 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 draft GDC-66, and 10 CFR 50.68 following implementation of the proposed EPU. In addition, TVA's proposed new TS 4.3.1.1.b is consistent with 10 CFR 50.36(c)(4) requirements to capture the importance of the limit on maximum fuel lattice reactivity for criticality safety. Therefore, the NRC staff finds the proposed EPU acceptable with respect to spent fuel storage.

2.9 Source Terms and Radiological Consequences Analyses

2.9.1 Source Terms for Radwaste Systems Analyses

Regulatory Evaluation

The NRC staff reviewed the radioactive source term associated with the EPU 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) draft GDC-70, 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. The radiation sources in the core during operation are expected to increase in proportion to the increase in power. Authorization to operate each Browns Ferry unit at 3,952 megawatts-thermal (MWt) is approximately a 20 percent increase from their originally licensed thermal power of 3293 MWt, or a 14.3 percent increase above the currently licensed thermal power of 3458 MWt. Therefore, a 20 percent increase in the original power level is expected to result in a proportional increase in the radiation source terms in the reactor core. However, this increase is bounded by the existing safety margins of the design basis sources. Since the reactor vessel (inside the fully-inerted primary containment) is inaccessible during operation, a proportional increase in the radiation sources in the reactor core will have no effect on occupational worker personnel doses during power operations. Due to design shielding and containment surrounding the reactor vessel, worker occupational doses are largely unaffected, and doses to the public from radiation shine from the reactor vessel remain essentially zero as a result of the power uprate. The licensee's analyses supporting the EPU amendment request included a core isotopic inventory calculated for the EPU conditions following methods and assumptions defined in RG 1.183 (Reference 161), "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors," Revision 0, July 2000. The analyses were performed at a power level of 4031 MWt, which is approximately 102 percent of the requested EPU power level of 3952 MWt.

Radiation sources in the reactor coolant include activation products, activated corrosion products and fission products. During operations, the reactor coolant passing through the reactor core region becomes radioactive as a result of nuclear reactions. The activation product concentrations in the steam will remain nearly constant following the power uprate since the increase in activation production in the steam passing through the core is proportional with the power increase, but will be balanced by the increase in steam flow through the core. While the concentration of activation products in steam will be approximately constant, the transit time from the core to the turbine building components will be reduced (due to increased steam flow rate). This decrease in transit time reduces the decay period of very short-lived radionuclides (mainly N-16), resulting in higher dose rates, roughly proportional to the power increase, in and around the turbine/condenser and other main steam components. The licensee states in PUSAR (Reference 47) Section 2.9.1, and the NRC staff agrees, that the margin in the Browns Ferry design basis for reactor coolant activation product concentration significantly exceeds

potential increases due to operation at EPU conditions. Therefore, no change is required in the design basis reactor coolant activation product concentration for operation at EPU conditions.

Fission products in the reactor coolant are assumed to partition between the steam and the reactor coolant. The activity in the steam consists of noble gases released from the core plus carryover activity from the reactor water. This activity is the noble gas off-gas that is included in the plant design. The licensee calculated the off-gas concentrations at 30 minutes of decay to be 3.6E+04 micro-curie/second (μCi/sec) under EPU conditions. This value is within the original design basis value of 3.5E+05 μCi/sec. Therefore, no change is required in the design basis for the off-gas activity under EPU conditions.

The licensee performed an evaluation of fission and activated corrosion products in the reactor coolant under EPU conditions. The isotopes used for comparing the design basis reactor water concentrations to the EPU reactor water concentrations were those isotopes that are common to both the Browns Ferry design basis and ANSI/ANS-18.1-1984. The total fission product activity under EPU conditions was calculated to be a fraction (2 percent) of the design basis fission product activity but the total activated corrosion product activity was calculated to be approximately 5 percent higher than the design basis activity. However, the sum of the fission and the activated corrosion products represents about 3 percent of the total design basis activity. Therefore, the NRC staff concluded that the design basis for the total fission and activated corrosion products remains unchanged.

Conclusion

The NRC staff has reviewed the radioactive source term associated with the proposed EPU and concludes that the proposed parameters and resultant composition and quantity of radionuclides are appropriate for the evaluation of the radioactive waste management systems. The NRC staff further concludes that the proposed radioactive source term meets the requirements of 10 CFR Part 20, 10 CFR Part 50, Appendix I, and draft GDC-70. Therefore, the NRC staff finds the proposed EPU acceptable with respect to source terms.

2.9.2 Radiological Consequences Analyses Using Alternative Source Terms

Regulatory Evaluation

The NRC staff reviewed the DBA radiological consequence analyses. The radiological consequence analyses reviewed were the LOCA, fuel handling accident (FHA), control rod drop accident (CRDA), and main steam line break (MSLB). The NRC staff's review for each accident analysis included (1) the sequence of events; and (2) models, assumptions, and values of parameter inputs used by the licensee for the calculation of the total effective dose equivalent (TEDE). The NRC's acceptance criteria for radiological consequences analyses using an alternative source term are based on (1) 10 CFR 50.67, insofar as it sets standards for radiological consequences of a postulated accident, 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 TEDE, as defined in 10 CFR 50.67, for the duration of the accident. Specific review criteria are contained in SRP Section 15.0.1.

RG 1.183 (Reference 161), "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors," Revision 0, July 2000 provides the methodology for

analyzing the radiological consequences of several design basis accidents to show compliance with 10 CFR 50.67. RG 1.183 provides guidance to licensees on acceptable application of alternative source term (AST) submittals, including acceptable radiological analysis assumptions for use in conjunction with the accepted AST.

Technical Evaluation

In Section 2.9.2, "Radiological Consequences Analyses Using Alternative Source Terms," of Enclosures 1 and 2 (updated PUSAR) to TVA letter dated October 28, 2016 (Reference 37), TVA stated, in part, that the effect of the proposed EPU on the radiological consequences of the LOCA, CRDA, MSLB Accident (MSLBA) and FHA is based on an assessment of the effect of EPU changes on the dose consequence analyses that were evaluated by the NRC in the safety evaluation for the Browns Ferry AST License Amendments 251, 290, and 249 (Reference 200), which approved a full-scope implementation of an AST that complies with the guidance given in RG 1.183 (Reference 161), "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors," and 10 CFR 50.67.

By letter July 30, 2012 (Reference 244), the NRC staff issued Amendments 282, 308, and 267, to revise the completion time to restore inoperable high-efficiency particulate air (HEPA) filters and charcoal adsorbers (7 days to restore an inoperable HEPA filter and 4 days to restore an inoperable charcoal adsorber). To support this change TVA revised the LOCA analysis to evaluate the impact on control room doses.

By letter dated March 9, 2016 (Reference 8), TVA responded to the RAIs associated with the dose analysis. Specifically, the NRC staff asked the licensee to provide the current licensing basis (CLB) and the revised EPU input values, assumptions, and methods, as well as a justification for any changes to the CLB. The NRC staff also requested that the licensee identify which of these parameters were not previously reviewed and approved by the NRC and to provide a justification for the change from the previously reviewed values to the CLB. TVA, in its response dated March 9, 2016, supplemented the above information with additional information regarding updates to the LOCA and CRDA analyses. TVA in the RAI response stated, in part, that:

> The LOCA analysis was subsequently [after approval of the AST] revised and approved in the license amendments issued for Technical Specification (TS) Change Request TS-474 as discussed below.
>
> and
>
> The changes in the dose due the changes to the CRDA inputs constitute a less than minimal change in the doses at the offsite receptor and at the control room [A change was made using 10 CFR 50.59 since the full scope implementation of the AST. The change made was to increase the leakage at the base of the plant stack leakage from 10 cubic feet per minute (cfm) (AST) to 20 cfm (EPU) to provide additional margin for damper testing].

Also, in response to an NRC staff RAI, TVA stated that there were no changes in the inputs or methodology for the FHA and MSLB design basis accident analyses previously reviewed and approved by the NRC for the AST (as documented in a safety evaluation dated September 27, 2004 (Reference 200)).

In addition to the proposed EPU, the licensee proposed a modification to the standby liquid control system (SLCS) Technical Specification 3.1.7 which included an increase in B-10 enrichment. Also, the peak suppression pool temperature previously analyzed is proposed to be reduced as a result of modified plant parameters in the anticipated transient without scram (ATWS) safety analysis, including an increase in SLCS B-10 enrichment, an increase in the credited SLCS storage tank boron concentration, and an increase in the credited SLCS flow rate. The LOCA radiological analysis currently assumes that sodium pentaborate is injected via the SLCS within 2 hours of the onset of the LOCA and that the suppression pool pH remains above 7 for the duration of the LOCA (30 days). Maintaining a pH greater than 7.0 for the duration of the accident analysis limits the re-suspension of iodine from the suppression pool liquid. In Section 2.9.2 of the PUSAR, TVA stated, in part, that the pH was evaluated to ensure that the pH would remain above 7 for the duration of the LOCA. TVA also stated that this evaluation shows that the suppression pool pH remains above 7 for the duration of the accident and ensures that the particulate form of iodine (CsI) would be retained in the suppression pool water and not re-evolve and become airborne as elemental iodine.

The NRC staff verified that the current license thermal power analyses for the LOCA, CRDA, MSLBA and FHA radiological consequences analysis are based on 4,031 MWt, which corresponds to the EPU power level of 3952 MWt with a 2.0 percent emergency core cooling system (ECCS) evaluation uncertainty factor applied. The NRC staff confirmed that the LOCA, MSLBA and FHA were previously reviewed and approved by the NRC in License Amendment Nos. 251 and 282 (Unit 1), 290 and 308 (Unit 2) and 249 and 267 (Unit 3) and reflect the proposed EPU conditions other than the changes reviewed by the NRC staff and discussed below.

2.9.2.1 LOCA

The NRC staff reviewed the proposed modifications to the SLCS. The staff reviewed whether the SLCS modifications would continue to ensure that the buffering action of the sodium pentaborate maintained the suppression pool's pH above 7 for a period of 30 days after the beginning of the accident. This review is documented in 2.1.8.1, "Standby Liquid Control System," of this SE. The staff concluded that with the proposed changes that the suppression pool's pH will remain above 7 for a period of 30 days after the beginning of the accident. Therefore, the previously reviewed and accepted portions of the LOCA radiological analysis relating to the SLCS is not impacted by the proposed changes to the SLCS.

TVA proposed to use the dose analyses approved in Amendments 251/282 (Unit 1), 290/308 (Unit 2) and 249/267 (Unit 3), which were done at the EPU power level, to justify the proposed EPU request. However, in a letter dated August 30, 2013 (Reference 245), TVA identified the alternative leakage treatment (ALT) pathway credited in the AST license amendments as being in a non-conforming/degraded condition. The degraded/non-conforming condition impacts the design configuration and accident response reviewed by the NRC staff and assumed for approval of the Amendment Nos. 251/282 (Unit 1), 290/308 (Unit 2) and 249/267 (Unit 3). In a letter dated May 29, 2015 (Reference 246), which was submitted to the NRC prior to the EPU LAR submittal, TVA stated that to resolve the existing non-conforming/degraded condition, TVA intends to perform facility and licensing basis modifications under 10 CFR 50.59 to assure that the current licensing basis dose calculations would remain valid.

As part of the review of the EPU LAR, the NRC staff asked TVA for additional information regarding the non-conforming condition and how with the non-conforming condition, the acceptance criteria for the radiological consequences analyses for 10 CFR 50.67 and GDC-19 are met. In a letter responding to the staff RAI, dated July 29, 2016 (Reference 28), TVA stated that it accepts the following license condition for resolution of the ALT pathway non-conforming/degraded condition:

> TVA shall perform facility and licensing basis modifications to resolve the non-conforming/degraded condition associated with the Alternate Leakage Treatment pathway such that the current licensing basis dose calculations (approved in License Amendment Nos. 251/282 (Unit 1), 290/308 (Unit 2) and 249/267 (Unit 3)) would remain valid. These facility and licensing basis modifications shall be complete prior to initial power ascension above 3458 MWt.

The above license condition places a limit on the operation of Browns Ferry Units 1, 2, and 3 to the currently authorized power level of 3458 MWt per unit, and prohibits operation above that limit until the modifications under the 10 CFR 50.59 process are complete and Browns Ferry meets its current licensing basis. Upon completion of the actions in the license condition, the design configuration and accident response will be consistent with that assumed in the above amendments and the current licensing basis calculations would be valid. Therefore, the previous findings in the safety evaluations in Amendment Nos. 251/282 (Unit 1), 290/308 (Unit 2) and 249/267 (Unit 3) would be valid at the EPU power level. The NRC staff concludes that, upon implementation of the license condition, there is reasonable assurance that the radiological consequences at the exclusion area boundary, outer boundary of the low population zone, and the control room are within the reference values provided in 10 CFR 50.67 and the accident specific dose guidelines specified in SRP 15.0.1. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to the radiological consequences of the LOCA contingent upon satisfaction of the above license condition.

2.9.2.2 CRDA

The current CRDA analysis was revised using the 10 CFR 50.59 process, but the licensee largely maintained consistency with the previously approved analyses with only a change to one CRDA input assumption. As discussed in the TVA's RAI response dated March 9, 2016 (Reference 8), the only assumption that changed is that the stack bypass leakage was increased from 10 cfm to 20 cfm to provide more margin for damper testing.

The NRC staff performed a confirmatory analysis to confirm the revised CRDA doses described in the March 9, 2016, RAI response. The NRC staff's analysis confirmed the revised CRDA doses provided by TVA; therefore, the NRC staff agrees that these doses continue to meet the applicable regulatory criteria for the CRDA.

The radiological consequences at the exclusion area boundary, outer boundary of the low population zone, and the control room are within the reference values provided in 10 CFR 50.67 and the accident specific dose guidelines specified in SRP 15.0.1. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to the radiological consequences of the CRDA.

2.9.2.3 Summary

Based upon the above evaluations and the previously approved analyses in Amendments 251/282 (Unit 1), 290/308 (Unit 2) and 249/267 (Unit 3), which were performed at EPU conditions, the NRC staff confirmed that with the EPU, the licensee continues to meet the TEDE at the exclusion area boundary for the limiting 2-hour period, at the outer boundary of the low population zone and in the control room for the duration of the accident, which is taken as 30 days for the LOCA, CRDA, MSLBA and FHA.

Conclusion

The NRC staff has evaluated the licensee's revised accident analyses performed in support of the proposed EPU and concludes that the licensee has adequately accounted for the effects of the proposed EPU. The NRC staff further concludes that the plant site and the dose mitigating engineered safety features remain acceptable with respect to the radiological consequences of postulated design basis accidents since, as set forth above, the calculated TEDE at the exclusion area boundary, at the low population zone outer boundary, and in the control room meet the exposure guideline values specified in 10 CFR 50.67 and final GDC-19, as well as applicable acceptance criteria denoted in SRP Section 15.0.1. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to the radiological consequences of design basis accidents.

As discussed above, to support the EPU approval, the above safety evaluation is contingent upon TVA completing the following license condition:

> TVA shall perform facility and licensing basis modifications to resolve the non-conforming/degraded condition associated with the Alternate Leakage Treatment pathway such that the current licensing basis dose calculations (approved in License Amendment Nos. 251/282 (Unit 1), 290/308 (Unit 2) and 249/267 (Unit 3)) would remain valid. These facility and licensing basis modifications shall be complete prior to initial power ascension above 3458 MWt.

2.10 Health Physics

2.10.1 Occupational and Public Radiation Doses

Regulatory Evaluation

The NRC staff conducted its review in this area to ascertain what overall effects the proposed EPU will have on both occupational and public radiation doses and to determine whether the licensee has taken the necessary steps to ensure that any dose increases will be maintained as low as is reasonably achievable. 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 (N-16) levels in the plant, on radiation doses outside the plant, and on radiation doses 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 and final GDC-19.

Specific review criteria are contained in SRP Sections 12.2, 12.3, 12.4, and 12.5, and other guidance provided in Matrix 10 of RS-001.

Technical Evaluation

2.10.1.1 Source Terms

Operation of each Browns Ferry unit at the EPU power level of 3,952 megawatts-thermal (MWt) would be an approximate 20 percent increase from the OLTP of 3293 MWt, and a 14.3 percent increase above the CLTP of 3458 MWt. In general, the production of radiation and radioactive material (fission and activation products) in the reactor core is directly proportional to the neutron flux and power level of the reactor. Therefore, a 20 percent increase in power level will result in a proportional 20 percent increase in the radiation source terms in the reactor fuel and the reactor coolant. For the majority of the dose estimates, the effects of the EPU on doses were evaluated assuming this proportional increase of 20 percent in the fission product inventory, and in the reactor coolant concentrations.

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 are expected to remain unchanged. The increased production rate (20 percent) of these materials is offset by a corresponding 20 percent increase in steam flow. Although the concentration of these materials in the steam line remains constant, the increased steam flow results in a proportionate increase in the rate these materials are introduced into the Main Condenser and Off Gas systems. As a result, the total inventory of materials in the main steam line, main condenser, and off gas systems increases by approximately 20 percent resulting in an approximately 20 percent increase in the source term.

2. For the very short lived activities, such as N-16 with its 7.13 second half-life, the decreased transit 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. As a result of the increased power level over the CLTP dose rates, the licensee estimates a 32 percent increase in expected dose rates from both the additional N-16 and an increase in other sources, based on its experience operating at Hydrogen Water Chemistry (HWC) conditions.

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. 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. However, the increased steam flow can result in an increased moisture carryover in the steam, which would result in an increased transport of the radioactive materials to the balance of the plant. As part of the EPU, the licensee is installing new steam dryers designed to accommodate the increase in steam flow at the uprated power to ensure that the moisture carryover remains at the current value of less than or equal to 0.1 weight percent. With the installation of the new steam dryers and increased steam flow, the rate at

which non-volatile fission products are introduced into the secondary will be proportional to the steam flow.

2.10.1.2 Radiation Protection Design Features

1. Occupational and onsite radiation exposures

The radiation sources in the reactor core are expected to increase in proportion to the increase in power. However, 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 percent increase in the radiation sources in the reactor core will not significantly increase occupational personnel doses during power operations.

Similarly, the radiation shielding provided in the original design of the balance of plant (i.e., around radioactive waste systems, main steam lines, the main turbine, etc.) was conservatively designed 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 in-plant dose rate increases due to the EPU will remain within acceptable limits for the zone designations and occupational exposures will continue to be maintained ALARA below the occupational dose limits in accordance with the radiation protection program.

The licensee in Section 2.10.1.1 of the PUSAR (Reference 37) stated that the impact of operating at a power level of 120 percent of OLTP will affect the radiological conditions during postulated accidents since increased radiological conditions will result from the increased core inventory of radioactive material. In order to meet acceptance criteria during accident conditions, the plant shielding design must be sufficient to provide control room habitability (per GDC-19), and to provide operator access to vital areas of the plant per NUREG-0737 item II.B.2. The dose rates in the control room (CR) and the technical support center (TSC) must be limited such as to allow occupancy without exceeding the occupational dose limits. In addition, the dose must be limited to within occupational dose limits for operators performing required emergency plant equipment operation. During emergency conditions, operators may be dispatched from the CR or TSC to perform plant operations such as to restart control bay chillers, to manually realign the HVAC equipment or to take samples from the post-accident sampling station. Based on the EPU power level of 3952 MWt, with an assumed 30 day post-accident occupancy period, the licensee calculated a 1.94 rem maximum TEDE dose to operators in the CR and in the TSC. TEDE doses for missions to restart control bay chillers and to manually realign the HVAC equipment were calculated to be less than 0.250 rem. Although the total mission dose to collect, transport and analyze the sample is greater than 5 rem, in a letter dated March 9, 2016 (Reference 8), the licensee stated that the tasks can be performed by separate individuals so that no single individual will receive a dose exceeding 5 rem. The NRC staff concludes that the licensee's evaluation is adequate because a single individual's post-accident doses will be kept below the 5 rem TEDE criteria in GDC-19 and are acceptable.

2. Public and offsite radiation exposures

The two factors associated with the EPU that may impact public and offsite radiation exposures during plant operations 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 storage of solid wastes, either directly or from atmospheric scatter (known as skyshine).

a. Gaseous Effluents, Liquid Effluents, and Solid Waste Storage

Operation at EPU conditions will result in a 20 percent increase in gaseous and liquid effluents released from the plant during normal operations. The licensee has demonstrated by calculation using the US NRC computer Boiling Water Reactor Gaseous and Liquid Effluent (GALE) code and the methodology in the Offsite Dose Calculation Manual (ODCM) and actual plant effluent release data for the period of 2009 through 2013 that the impact of this change will not increase the radiation exposure to the public above acceptance criteria.

Operation of the plant at EPU conditions was determined to result in an annual whole body dose of 1.47 mrem to a member of the public from plant gaseous effluent and an annual whole body dose of 0.042 mrem from plant liquid effluents at the site boundary. Therefore, these public doses will continue to meet the design criteria in 10 CFR Part 50, Appendix I, the Environmental Protection Agency standard in 40 CFR Part 190 of 25 mrem per year, and the NRC's 100 mrem per year public dose limits in 10 CFR Part 20. Additionally, the licensee provided the actual plant effluent average release data from 2009 through 2013 that shows the actual annual whole body doses from gaseous and liquid effluent releases were 2.15E-03 mrem and 1.40E-02 mrem respectively, which are substantially less than the public doses estimated under EPU conditions.

The EPU will also result in increased generation of liquid and solid radioactive waste. The increased condensate feed flow associated with the EPU results in faster loading of the condensate demineralizers. Similarly, the higher feed flow introduces more impurities into the reactor resulting in faster loading of the reactor water cleanup system filter-demineralizers. Therefore, the demineralizers in both of these systems will require more frequent backwashing. The licensee has estimated that these more frequent backwashes will increase the volume of liquid waste needing processing by about 3.44 percent. This increase will result in a total volume that is less than the processing capacity of the Browns Ferry radioactive waste system and is not expected to significantly increase the liquid effluents or solid radioactive waste released from the plant. Therefore, these increases will have a minor impact on occupational or public radiation exposure.

b. Direct Public Radiation Exposure

Nitrogen-16 emits an energetic gamma (either a 6.1 or 7.1 MeV per transformation) and can be a source of direct radiation exposure offsite at facilities with small sites from skyshine. Browns Ferry is a large site (e.g., distance to site boundary at nearest land area is approximately 1410 m (0.9 mile)) and therefore, the impact from direct radiation (skyshine) is negligible and not measurable using state-of-the art environmental dosimeters. In a letter dated March 9, 2016 (Reference 8), the licensee indicated that current environmental dosimeter measurements have not identified any increase in direct radiation levels as compared to levels measured during pre-operational and construction phases of the plant. Therefore, even a 32 percent increase in gamma

radiation from turbine building components postulated following the EPU would still result in an insignificant impact on public dose from skyshine.

Direct radiation from the independent spent fuel storage installation (ISFSI) and condensate storage tanks (CST) are also contributors to offsite doses due to direct radiation shine. The licensee has estimated the annual dose to the maximally exposed individual from the ISFSI and the CST at an unoccupied river location 400 meters (0.25 mile) from these sources to be 13.8 mrem (whole body) and 7.23 mrem (whole body), respectively. Additionally, the licensee estimated the annual dose from gaseous effluents to be 0.742 mrem due to the design basis leak rate of ISFSI casks at the same location.

c. Total Site Boundary and Public Dose

The total annual radiation dose at the site boundary from power operation at EPU conditions is 23.3 mrem. This is determined by summing the direct radiation doses from the ISFSI and the CST and doses from all gaseous and liquid effluent pathways. The offsite dose to the highest member of the public is much lower than this due to the distance to the nearest resident based on a land use census of 1410 meters (0.9 miles). This annual dose is within the applicable 10 CFR Part 20 annual limit of 100 mrem, and the 40 CFR Part 190 annual limit of 25 mrem to a real member of the public from the reactor fuel cycle, as referenced by 10 CFR 20.1301 (e).

2.10.1.3 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 Browns Ferry (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 the EPU. Therefore, the increased radiation sources resulting from the proposed EPU, as discussed above, will not adversely impact the licensee's ability to maintain occupational and public radiation doses as low as is reasonably achievable and within the applicable limits in 10 CFR Part 20.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on radiation source terms and plant radiation levels. The NRC staff concludes that the licensee has taken the necessary steps to ensure that any increases in radiation doses will be maintained as low as reasonably achievable. The NRC staff further concludes that the proposed EPU meets the requirements of 10 CFR Part 20 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 as low as reasonably achievable.

2.11 Human Performance

2.11.1 Human Factors

Regulatory Evaluation

The area of human factors deals with programs, procedures, training, and plant design features related to operator performance during normal and accident conditions. The NRC staff's human factors evaluation was conducted to ensure that operator performance is not adversely affected as a result of system changes to be implemented for 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 (Reference 247). Specific review criteria are contained in SRP Sections 13.2.1, 13.2.2, 13.5.2.1, and 18.0.

Technical Evaluation

The NRC staff has developed a standard set of questions for the review of the human factors area in RS-001. The licensee has addressed these questions in its application dated September 21, 2015 (Reference 1). 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 on the Safety Parameter Display System
5. Changes to the Operator Training Program and the Control Room Simulator
6. Operating Experience

Each topic below includes the scope of review consistent with RS-001, the information provided by the licensee, and the NRC staff evaluation.

1. Changes in Emergency and Abnormal Operating Procedures

Scope

Describe how the proposed EPU will change the plant emergency and abnormal operating procedures. Specific review criteria are contained in SRP Section 13.5.2.1.

Information Provided by Licensee

The licensee, in PUSAR (Reference 37), Section 2.11.1.1 "Changes in Emergency and Abnormal Operating Procedures," identified various curves and values that will change as a result of the EPU in the Emergency Operating Procedures (referred to as emergency operating instructions or EOIs by the licensee) and in the severe accident management guidelines. The licensee also identified those specific EOIs that utilize these particular curves and values. (Section 3.3.2 "Procedural Changes" of Attachment 44 (Reference 54) of the LAR (Reference 1) provides a similar and consistent description.)

The licensee, in Section 2.11.1.1 of PUSAR (Reference 37), similarly identified and described changes to abnormal operating procedures (AOPs) (called abnormal operator instructions or AOIs by the licensee), annunciator response procedures (ARPs), fire safe shutdown (FSSs) and operator instructions (OIs) that may be affected by the EPU.

The NRC staff in an RAI requested the licensee provide schedules for completion of procedures and describe validation activities that will be conducted to determine if operators can accurately complete all time critical tasks within the time allowed by analysis. The licensee, in its response dated April 22, 2016 (Reference 14), clarified that all procedure modifications will be completed and verified using the licensee's established procedure validation process prior to EPU implementation at each unit.

NRC Staff Evaluation

The NRC staff finds that the licensee provided a reasonable schedule for completion and described the use of the established procedure validation process to ensure that all procedure modifications are implemented appropriately.

Some curves and values identified in the procedures described above change as a result of EPU, however there is no change to the underlying emergency response philosophy contained in these procedures. Therefore, the changes should not present significant challenges to operators as a result of implementation.

Therefore, the staff finds the licensee's response meet the SRP Section 13.5.2.1 criteria and is acceptable.

2. <u>Changes to Operator Actions Sensitive to Power Uprate</u>

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. Specific review criteria are contained in SRP Section 18.0.

Information Provided by Licensee

The licensee in PUSAR (Reference 37), Section 2.11.1.2 "Changes to Operator Actions Sensitive to Power Uprate" identifies three types of events with associated operator manual actions that are affected by this LAR. The licensee indicates that there are no changes to automatic safety functions as a result of this LAR. However there are some changes to operator actions.

a. The licensee in PUSAR, Section 2.11.1.2.1 "Changes for Design Basis Accidents and Events" described a change to a time sensitive operator action as a result of this LAR: "Crosstie of the Containment Atmospheric Dilution system to the Drywell Control Air System." This time sensitive action must be completed in the control room within 2 hours of a station blackout event. This action is described as a simple task that takes less than 10 minutes to complete.

The licensee in its April 22, 2016, RAI response (Reference 14) clarified that this time-critical operator action is not a new action and that previous time validation indicated that the action can be completed within 10 minutes. The licensee described unambiguous cues that indicate the need to perform this action. The licensee included this task in the training program and nine operators successfully performed this specific task as recently as October 2015 as a job-performance measure. The licensee identified existing EOI/AOIs used to complete this task. The licensee also indicated that this time-critical operator action was revalidated using three crews prior to EPU implementation.

b. The licensee in PUSAR (Reference 37), Section 2.11.1.2.2 "Fire Safe Shutdown (FSS) Events" provided a high-level summary of the use of fire procedures and the associated changes as a result of this LAR.

   The licensee's April 22, 2016 (Reference 14), RAI response letter clarified that FSS Events were previously analyzed by the NRC and approved as part of the recent NFPA 805 license amendment. There are no changes to these actions as compared to those that were approved in the NFPA 805 amendment (i.e., changes to human-system interfaces, operator action times, procedures, training, etc.) Therefore, additional review of these actions is not necessary.

c. The licensee in PUSAR (Reference 37), Section 2.11.1.2.3, "Anticipated Transient Without Scram," partially described a manual action which is not credited in the accident analysis, but is available to operators to provide water to the reactor pressure vessel. This section indicated there are no changes to the timing of this action; however, there are changes to the cold and hot shutdown boron weights and decay heat removal pressure.

The April 22, 2016 (Reference 14), submittal clarified that the ATWS actions described do not change as a result of the EPU. They are currently credited at EPU power levels by the Human Reliability Analysis (HRA). There are no changes to human-system interfaces, procedures, or training necessary to support these actions.

Section 2.11.1.2.4 "Conclusions" of PUSAR (Reference 37) indicated that there is only a single change to the operator manual actions that affects the timing of the action (described in Number 2.a above). It also clarified that changes to operator actions will be reflected in procedures and training prior to implementation].

NRC Staff Evaluation

The licensee's submittal described three classes of actions affected by the EPU. Two of them, ATWS actions and Fire Safe Shutdown Event Actions are unchanged from the current licensing basis and therefore additional review of these actions is not necessary.

The NRC staff reviewed the remaining time-critical operator action: "Crosstie of the Containment Atmospheric Dilution system to the Drywell Control Air System." Only the risk associated with the action changes as a result of the EPU. The actions performed by operators are unchanged. Operators are trained on this action regularly. There are unambiguous annunciators which provide cues that the action is necessary. The 10 minutes needed to complete the action is substantially less than the time available (2 hours) leaving significant time margin to complete the task. The 10 minute time estimate is substantiated by recent time-critical action validations and job-performance data. Actual performance data from the various sources described in the submittal is used to substantiate the time estimate provided by

the licensee (as opposed to table top exercises or other time estimation methods). The large amount of margin compared to short amount of time needed to complete the action makes it extremely unlikely that operators will fail to meet the time requirements. In addition, the licensee plans to revalidate the action prior to implementation of the EPU. Therefore, the staff finds the licensee's response for operator actions acceptable.

3. Changes to Control Room Controls, Displays and Alarms

Scope

Describe any changes the proposed EPU will have on the operator interfaces for control room controls, displays, and alarms. 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. Specific review criteria are contained in SRP Section 18.0.

Information Provided by Licensee

The licensee in PUSAR (Reference 37), Section 2.11.1.3 "Changes to Control Room Controls, Displays and Alarms," provided a list of human-system interfaces (HSIs) that will be installed, changed, or removed to support this LAR. The licensee provided additional detail about the design of these components in its April 22, 2016 (Reference 14), RAI response submittal. The licensee described, in depth, the types of controls that will be installed and/or modified as a result of the EPU modifications. Training will be provided for new controls, and several of the controls necessary for EPU operation were installed during a previous outage, which assures that operators are already familiar with them. Furthermore, the licensee described how training and procedure updates will be used to ensure that changes to setpoints will be made explicit to operators.

The licensee also provided in depth descriptions of how it will ensure that changes to rated power will not cause the corresponding changes to various plant parameters and limits to become difficult for operators to accurately estimate. A variety of methods were described including (but not limited to): updating procedures with appropriate values, operator training, use of automatic action that precludes the need for operator mental calculations, and others. Changes to HSIs were generally unnecessary (other than changes to some setpoints that initiate automatic actions). Zone markings will be updated on the A and B analog loop gauges to reflect the amount of liquid nitrogen in each Containment Atmospheric Dilution (CAD) system nitrogen storage tank. There are no upgrades that involve converting analog components to digital components.

Section 2.11.1.3 of PUSAR (Reference 37) also described how the design change process is used to update the simulator and the training program.

NRC Staff Evaluation

With the exception of the zone markings for the CAD system nitrogen storage tanks, there are no changes to the displays as a result of the EPU. The licensee described the actions taken to ensure that operators are able to monitor the system status for the parameters that will be affected by the EPU. The licensee will train operators about the changes to setpoints to ensure that they are aware of changes to the inner workings of the HSIs that are not readily apparent.

In addition, the licensee describes changes to controls, which are minimal, and are consistent with other similar controls which decreases the probability of error and/or operator confusion. Therefore, the staff finds this treatment to be acceptable.

4. Changes on the Safety Parameter Display System

Scope

Describe any changes to the safety parameter display system resulting from the proposed EPU. Explain how the operators will know of the changes. Specific review criteria are contained in SRP Section 18.0.

Information Provided by Licensee

Section 2.11.1.4 "Changes to the Safety Parameter Display System (SPDS)" of PUSAR (Reference 37) describes changes to two operational curves (HCTL and PSP curves) that are made as a result of the Browns Ferry EPU, which are instrumental to the SPDS. The HCTL curve will be revised as a result of the additional decay heat rejected to the suppression pool. The PSP curve will be revised as a result of the increase in decay heat rejected to the suppression pool. The changes to both curves are minimal (as described in Section 2.11.1.1 "Changes in Emergency and Abnormal Operating Procedures.") These changes are not expected to significantly affect operator actions and will be conducted in accordance with the configuration change process.

Section 2.11.1.4.1 "Conclusion" indicates that operators will receive classroom and/or simulator training before the EPU is implemented. This ensures that the operators will know of the change as indicated in the criterion.

NRC Staff Evaluation

The licensee described the changes that will be made to the SPDS and explained that the changes will be made in accordance with the configuration change process and the operators will receive appropriate classroom and simulator training prior to implementation. Therefore, the NRC staff finds the licensee's response for this criterion acceptable.

5. Changes to the Operator Training Program and the Control Room Simulator

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. Specific review criteria are contained in SRP Sections 13.2.1 and 13.2.2.

Information Provided by Licensee

PUSAR (Reference 37), Section 2.11.1 "Human Factors" described the configuration change process that includes a review for procedures requiring revision and training. The training organization reviews all plant modifications and procedure changes and applies the systematic approach to training. The results of this process are used to modify the physical and modeling characteristics of the simulator accordingly.

In addition, Section 2.11.1.5 "Changes to the Operator Training Program and the Control Room Simulator" indicates Operations personnel receive training for all EPU related modifications. Operator training consists of classroom and simulator training.

Training is planned for both licensed and non-licensed operators prior to the fuel cycle in which the changes will be implemented. These changes focus on plant modifications, procedure changes, startup test procedures, and changes to parameters such as setpoints, scales, and systems. Training uses common methods including written exams, simulator evaluations, and task performance tools. Just-in-time training is planned for last minute training items and startup training and startup testing evolutions.

Browns Ferry is a three unit site with two simulators that closely mimic the control rooms for Units 2 and 3. Unit 1 is very similar to Unit 2; therefore, the Unit 2 simulator is used for training for Unit 1. Classroom training and the use of mockups are used to account for any differences between the Unit 2 simulator and the Unit 1 control room. Modification to the simulators is conducted in accordance with ANSI/ANS-3.5 1985, "Nuclear Power Plant Simulators for Use in Operator Training."

NRC Staff Evaluation

Based on the licensee's use of controlled processes to identify training needs and simulator updates, the use of evaluation tools, the use of a systematic approach to training based process, and an indication that training will be complete prior to implementation of EPU operations, the staff finds the proposed approach to training and simulator updates acceptable.

6. Operating Experience Review (OER)

Information Provided by Licensee

The April 22, 2016 (Reference 14), RAI supplement letter described the OER conducted by the licensee. The licensee reviewed a wide variety of relevant operating experience resources including INPO reports, Boiling Water Reactor Owners Group reports on the EPU, and other sources. The licensee also described several issues that were discovered as well as high-level descriptions of actions taken to prevent/mitigate recurrence of these issues.

NRC Staff Evaluation

The NRC staff finds that the licensee described operating experience based on other similar EPUs and provided plans for preventing/mitigating similar effects for each issue that was identified. Therefore, the staff finds the licensee's response acceptable.

Conclusion

The NRC staff has reviewed the changes to operator actions, human-system interfaces, procedures, and training required to support 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

Regulatory Evaluation

The purpose of the EPU test program is to demonstrate that SSCs will perform satisfactorily in service at the proposed EPU power level. The test program also provides additional assurance that the plant will continue to operate in accordance with design criteria at EPU conditions. The NRC staff's review included an evaluation of: (1) plans for the initial approach to the proposed maximum licensed thermal power level, including verification of adequate plant performance, (2) transient testing necessary to demonstrate that plant equipment will perform satisfactorily at the proposed increased maximum licensed thermal power level, and (3) the test program's conformance with applicable regulations. The NRC's acceptance criteria for the proposed EPU test program are based on 10 CFR Part 50, Appendix B, Criterion XI, which requires establishment of a test program to demonstrate that SSCs will perform satisfactorily in service. Specific review criteria are contained in SRP Section 14.2.1.

Technical Evaluation

This section of the SE focuses on the NRC staff's evaluation of the EPU power ascension test plan (PATP) related to the RSDs that is provided in detail in the LAR, Attachment 40 (NEDC-33824P), "Browns Ferry Replacement Steam Dryer Stress Analysis of the EPU," Appendix E. The PATP is also briefly summarized in Section 6.2 of NEDC-33824P (see (Reference 147) for non-proprietary version of Attachment 40). Attachment 46 (Reference 56) of the EPU LAR describes startup testing for EPU implementation. Following the respective refueling outages scheduled in the spring of 2018 outage for Unit 3, in the fall of 2018 outage for Unit 1, and the spring of 2019 outage for Unit 2, TVA will conduct a comprehensive EPU startup test program to ensure the safe operation of each Unit.

The installations of RSDs and new MSL strain gauges are scheduled for BFN Unit 3 during the spring of 2018 outage, for BFN Unit 1 during the fall of 2018 outage, and BFN Unit 2 during the spring of 2019 outage. Also, the installation of BFN on-dryer instrumentation for Unit 3 RSD is scheduled during spring 2018 (RFO-U3R18) refueling outage. The acoustic vibration suppressors (AVSs) inside the 6-inch diameter blind flanged branch lines to reduce acoustic loading on the steam dryer are already in place for the three BFN units.

A Browns Ferry's power ascension test procedure incorporates the tests from the EPU startup test plan as well as any testing required from other modifications installed during these outages.

The Browns Ferry EPU flow induced vibration PATP describes the planned course of action 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 such as the RSD during power ascension testing and operation from the CLTP to the EPU power level.

The PATP covers power ascension up to the full EPU condition to verify acceptable structural performance and RSD integrity. Through the establishment of acceptance limits, data collection and analysis, and any subsequent actions, the PATP will ensure that the integrity of the RSD will be maintained. An important element of the PATP during the power ascension to the CLTP is the benchmarking of the plant based load evaluation (PBLE) load definition and structural analysis methodology using Browns Ferry specific measured data. During the refueling outage, to prepare for EPU power ascension monitoring and data collection, new sets of strain gauges will be installed on all four main steam lines (MSLs) for the three Browns Ferry units. The lead unit (BFN Unit 3) RSD will also be instrumented with strain gauges, accelerometers and pressure transducers. The data from these instruments will be used to benchmark the PBLE load definition and RSD structural response during the power ascension to CLTP and EPU plant conditions

The licensee stated that the PATP includes general hold points (plateaus) and durations during power ascension above CLTP, activities to be accomplished during hold points, data to be collected, data evaluation methods, and acceptance limit criteria for monitoring and trending plant parameters. Detailed procedures are developed for implementation during power ascension. This PATP assesses the steam dryer structural performance for the Browns Ferry EPU start-up power ascension process. The main steps for the power ascension testing are as follows:

1. Ascension to CLTP: RSD and MSL strain, acceleration and pressure data are collected and processed at a minimum of three power levels up to CLTP.

2. At CLTP: RSD and MSL strain, acceleration and pressure data are collected and processed, an evaluation of strain and pressure data against acceptance limits is performed, a structural evaluation at CLTP is performed, and the acceptance limits are reevaluated if required.

3. Ascension above CLTP to EPU: RSD and MSL strain, acceleration and pressure data are collected and processed, an evaluation of strain and pressure data against acceptance limits at every test plateau is performed, and the acceptance limits are reevaluated if required.

4. Data collection is performed at full EPU power across the licensed core flow range, to evaluate dryer structural response to changes in the reactor core flow and recirculation pump vane passing frequency excitation.

The PATP assesses the RSD structural performance for the Browns Ferry EPU power ascension process. The power ascension will be implemented in two phases. The first phase covers power ascension to 3458 MWt, (CLTP plant condition). The second phase covers the power ascension above 3458 MWt. to 3952 MWt. (EPU plant condition), which consists of hold points at predetermined increments of approximately 5 percent power or 165 MWt.

There are three main elements of the first phase PATP, up to and including the CLTP test points:

1. Start power ascension to the CLTP with defined test points and durations, allowing time for monitoring and analysis.

2. A detailed power ascension monitoring and analysis program to trend the RSD structural response, and to assess the adequacy of the FIV load definition and RSD acoustic and structural finite element models for predicting the responses significant to peak stress projections. This will be determined through the evaluation of data from the on-dryer pressure transducer and strain gauge instrumentation (lead unit only: BFN Unit 3) or the MSL strain gauges (follow-on units: BFN Unit1 and BFN Unit 2) at a minimum of three power levels up to CLTP. The power ascension for the Browns Ferry lead unit (BFN Unit 3) will be monitored using on-dryer pressure transducers, strain gauges, and accelerometers. The instrumentation design ensures that there is sufficient and appropriate instrumentation to define the vibratory and stress response for those components in the Browns Ferry RSD that have been modified relative to the valid prototype BWR/4 steam dryer. In addition to the on-dryer instrumentation, the MSLs for BFN Unit 3 will also be instrumented in order to aid in developing the test acceptance criteria for the follow-on units. Test acceptance criteria for BFN Unit 3 will be provided through limit curves for the on-dryer structural response sensors based on FIV analysis results.

   The confirmatory analysis for the lead unit (BFN Unit 3) will provide the basis for the test acceptance criteria for the follow-on units (BFN Unit 1 and BFN Unit 2). Power ascension monitoring for BFN Unit 1 and BFN Unit 2 will be performed using MSL strain gauges; because the RSDs will not be instrumented with on-dryer sensors. Test acceptance criteria for BFN Unit 1 and BFN Unit 2 will be provided through limit curves for the PBLE02 projected steam dryer loads using the MSL acoustic pressure measurements. The projected steam dryer load limits will be based on the load definition from the BFN Unit 3 confirmatory analysis.

3. For the lead unit, the RSD strain gauge data at the CLTP will be used to update the end-to-end bias and uncertainty and revise the model projections used in the EPU licensing basis analysis. To assure the existing models adequately capture the RSD response, an evaluation will be performed at the CLTP to determine if the current FEA predictions are adequate or if either adjustments or a complete reanalysis are required. If the measured RSD strains are not within the acceptance limits, a full structural re-analysis will be performed to evaluate the RSD using the on-dryer measured data prior to proceeding with power ascension above CLTP. The RSD stress projections will be revised and, if necessary, the on-dryer strain gauge acceptance limits, and the FIV pressure load acceptance limits will be updated. The stress projection and acceptance limit revisions will be performed using the narrow band RMS method, consistent with the stress adjustment methodology.

For the follow-on units (BFN Unit 1 and BFN Unit 2), the dryer pressure loads projected by PBLE02 using the MSL strain gauge measurements of the acoustic pressure loads in the steam lines will be compared against the acceptance limits defined in the LAR (Reference 1), Attachment 40, Appendix E, Section 6.0. The RSD stress projections will be revised and, if necessary, the FIV pressure load acceptance limits will be updated.

The second phase of PATP (CLTP to EPU test points) consists of four main elements:

1. Slow and deliberate power ascension to the EPU power level with defined hold points and durations, allowing time for monitoring and analysis.

2. For the lead unit during power ascension above CLTP, comparing the on-dryer sensor measurements against the acceptance limits described in Section 5 of NEDC-33824P will be the primary method for monitoring the lead unit RSD structural response. In the event that the minimum required on-dryer sensors are not operable, then the lead unit RSD will be monitored using projected dryer loads based on MSL strain gauge measurements.

   For the follow-on units (BFN Unit 1 and BFN Unit 2), the projected dryer loads comparison will be based on the MSL strain gauge measurements against the MSL based acceptance limits.

3. For the lead unit (BFN Unit 3), on-dryer measurements will be collected at full EPU power across the licensed core flow range for evaluating the dryer structural response to changes in reactor core flow and recirculation pump vane passing frequency excitation.

4. Reactor parameters will be monitored which are potentially indicative of RSD structural degradation such as individual channels of RPV pressure, reactor water level, MSL steam flow, and moisture carry over (MCO). The acceptance limit for MCO is [[ ]].

The assessment of the RSD structural integrity for the lead unit will be completed by analysis using the measured on-dryer strains and acceleration data. The assessment of the RSD structural integrity for BFN Unit 1 and BFN Unit 2 will be completed through the analysis of the dryer pressure loads projected from the MSL strain gauge measurements of the acoustic pressures in the steam lines.

Vibration monitoring of main steam, feedwater, and other balance of piping will be performed to assess the effect of the EPU on piping. A detailed discussion of the analysis and testing program undertaken by TVA to provide assurance that unacceptable FIV will not be experienced at BFN due to EPU implementation for the affected piping systems is provided in Attachment 45 of the EPU LAR (Reference 1). NRC Regulatory Guide (RG) 1.20 (Reference 142) provides guidance and information for evaluating the potential adverse flow effects from pressure fluctuations and vibrations in piping systems for BWR nuclear plants.

The NRC staff reviewed the Browns Ferry power ascension and startup test plans for TVA's 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. TVA, along with using the startup test plan, plant procedures, and processes, will assure the functions of plant equipment important to safety are adequately demonstrated prior to operation at the EPU power level.

Further, the NRC staff compared the proposed license conditions for Browns Ferry with those applied during previous EPU power ascensions. Similar to the previously approved EPUs, Browns Ferry power ascension testing will have two separate criteria, namely 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 at a reduced power level 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. 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. 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 NRC staff finds that the Browns Ferry PATP is 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 (Reference 146), BWRVIP-139-A (Reference 192), and GE SIL-644 (Reference 248), and therefore are acceptable.

The BFN Unit 3 RSD will have 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 the CLTP. The BFN Units 1 and 2 RSDs which will follow the Unit 3 EPU power ascension, will only have MSL strain gauges and consider BFN Unit 3 as the prototype. The BFN Units 1 and 2 RSD analyses will be updated to use B&Us from the BFN Unit 3 end-to-end benchmark after the completion of the BFN Unit 3 power ascension.

In response to the NRC staff's request to address the scenario of the possible failure of on-dryer sensors of the lead BFN Unit 3, the licensee provided information on PATP contingencies regarding loss of on-dryer instrumentation. Basically, the licensee will utilize MSL strain gauge data during power ascension, as discussed in TVA's response to the NRC staff's RAIs in Supplements 30 and 33 (Reference 35) and (Reference 36).

Thus, the licensee has adequately addressed the scenario of failure of the lead BFN Unit 3 on-dryer instrumentation, in which case the power ascension will be based on MSL SG data and the design basis [[ ]]. The NRC staff finds that the Browns Ferry PATP and the applicable license conditions shown in Section 3.1.3 of this SE 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 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 adequate 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.

2.12.2 Additional Review Areas (Startup Test Plan)

Regulatory Evaluation

Guidance for startup testing and power ascension to the EPU power level is provided in SRP, Section 14.2.1, "Generic Guidelines for Extended Power Uprate Testing." In addition, the licensee used the guidance that is provided in NEDC-32424P-A, "Generic Guidelines for

General Electric Boiling Water Reactor Extended Power Uprate," (ELTR-1) (Reference 49), February 1999, NEDC-32523P-A, "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate," (ELTR-2) (Reference 50), February 2000, and NEDC-33004P, "Constant Pressure Power Uprate" (Reference 48), Revision 1, July 2001.

RG 1.68, "Initial Test Programs for Water-Cooled Nuclear Power Plants," Revision 4, June 2013 describes the general scope and depth of initial test programs that the NRC staff has found acceptable during the review of original operating license applications. The initial startup tests are described in Section 13.5 of the Browns Ferry UFSAR.

The acceptance criteria for steady-state and transient power ascension testing applicable to EPUs are provided in Tables 1 and 2 of SRP Section 14.2.1

Technical Evaluation

The licensee provided a "Startup Test Plan" in Attachment 46 (Reference 56) of the EPU LAR. Modifications related to the EPU are listed in Attachment 47 of the EPU LAR, as supplemented in Table 1 of Enclosure 5, "BFN EPU LAR, Attachment 47, List and Status of Plant Modifications, Revision 4," (Reference 39). The required modifications to support the EPU for the three BFN units will be installed by the licensee prior to EPU implementation as summarized in Table 1 of Attachment 47, Revision 4, with some of the modifications already completed. The RSD installation and new MSL strain gauge installation schedule is as follows: BFN Unit 3 in the spring of 2018 outage, for BFN Unit 1 in the fall of 2018 outage, and BFN Unit 2 in the spring of 2019 outage. On-dryer instrumentation for the BFN Unit 3 RSD will also be installed during spring 2018 (RFO-U3R18). The acoustic vibration suppressors (AVSs) inside the 6-inch diameter blind flanged branch lines to reduce acoustic loading on the steam dryer are already in place for the three BFN units.

The comprehensive startup test plan is intended to assure that the plant equipment and Replacement steam dryers will function adequately prior to operation at the EPU power level. Steam dryer and separator performance will be confirmed within limits by determination of steam moisture content and by evaluating steam dryer dynamic loading during power ascension testing. The steam dryer monitoring will be based on a slow and deliberate power increase above CLTP with specified hold points at power increments of approximately 5 percent. The steam dryer will have level 1 and level 2 acceptance criteria.

The EPU startup test plan is integrated with testing of other modifications to demonstrate that all modifications have been adequately implemented. The licensee will develop the post modification testing needed for each of the modifications, listed in the Revision 4 of Attachment 47, in accordance with the Browns Ferry modification program. Performance testing for these, and any other modifications installed during the EPU outages, will be integrated into a single, controlling power ascension test procedure, as necessary, to ensure the aggregate effect of the EPU and all modifications do not affect the safety performance of BFN Units 1, 2, and 3.

The NRC staff reviewed the BFN startup test plan, and finds it to be comprehensive and similar to that of other plants that successfully implemented an EPU. The aggregate impact of EPU plant modifications, setpoint adjustments, and parameter changes will be demonstrated by the licensee using the comprehensive startup test program. The startup test program is in accordance with BWR EPU startup test specifications established by analysis as well as GEH

BWR experience, described in the revised PUSAR (Reference 37). Therefore, the NRC staff finds the comprehensive BFN startup test plan acceptable.

Based on its review, the NRC staff finds that the BFN startup and the applicable license conditions shown in Section 3.1.3 of this SE 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. The licensee has adequately identified the plant modifications and setpoint adjustments in the EPU LAR.

Conclusion

The NRC staff concludes that the proposed EPU test program will adequately demonstrate the performance of SSCs important to safety that meet any of the following criteria: namely: (1) the performance of the SSC is impacted by EPU-related modifications, (2) the SSC is used to mitigate an anticipated operational occurrence described in the plant-specific design basis, and (3) performance of the SSC can be affected by integrated plant operation or transient conditions, will continue to function in accordance with their design criteria during steady-state and transient operating conditions, because they will be subjected to appropriate testing requirements,

Therefore, the staff concludes that the comprehensive Browns Ferry startup test plan is acceptable, and that there is reasonable assurance that SSCs will maintain adequate margins at EPU operation.

2.13 Risk Evaluation

2.13.1 Risk Evaluation of the 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, "Use of Risk Information in Review of Non-risk-informed License Amendment Requests," of SRP Chapter 19.2, 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, fire, seismic, shutdown, and other external events. 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 examination of external events (IPEEE), or by an industry peer review. The NRC's risk acceptability guidelines are contained in RG 1.174, Revision 2 (Reference 249). Specific review guidance is contained in Matrix 13, "Scope and Associated Technical Review Guidance, Risk Evaluation," of RS-001 and its attachments.

Technical Evaluation

The risk evaluation of the proposed EPU is in Section 2.13, "Risk Evaluation," of the PUSAR (Reference 37) and Attachment 44 (Reference 54), "Probabilistic Risk Assessment," to the LAR (Reference 1). The licensee did not request the relaxation of any deterministic requirements for the proposed EPU, and the NRC staff's approval is primarily based on the licensee meeting the current deterministic requirements.

2.13.1.1 Probabilistic Risk Assessment (PRA) Model Quality

The quality of a licensee's probabilistic risk assessment (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.

Individual Plant Examination of External Events

By letters dated July 24, 1995 (Reference 250), June 28, 1996 (Reference 251), July 11, 1997 (Reference 252), and January 14, 2005 (Reference 253), the licensee submitted the IPEEE for Browns Ferry in response to GL 88-20, Supplement 4, "Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities," dated June 28, 1991 (Reference 254). The IPEEE study used the Electric Power Research Institute (EPRI) Seismic Margins Analysis (Reference 255) methodology to address risk from seismic. The Unit 2 and 3 seismic IPEEE submittal identified items for seismic margin improvement. The Unit 1 seismic IPEEE submittal identified outliers associated with the unresolved safety issues (USI) A-46," Seismic Qualifications of Equipment in Operating Plants," screening evaluations (Reference 253). The licensee in its submittal for the EPU LAR stated that these identified vulnerabilities and outliers have all been addressed and corrected through the corrective action program. A screening approach as described in GL 88-20, Supplement 4, was used for the evaluation of high winds, external floods, and transportation and nearby facilities' accidents. This screening approach used in analysis of external floods and nearby facilities/transportation accidents demonstrates that they meet the NRC's SRP 1975 (Reference 256) criteria and have adequate defense against these threats. Since Browns Ferry does not meet the SRP 1975 criteria for high winds, a bounding analysis was performed. This analysis showed the contribution to core damage frequency due to high winds to be less than the IPEEE screening criteria of 1E-06 (Reference 250). Internal fires were originally evaluated in the IPEEE. However, since the performance of the IPEEE, a detailed fire PRA (FPRA) has been developed for all three units and was used to evaluate the impact of EPU conditions, as discussed below.

The NRC staff's review of the BFN IPEEE, Unit 1, 2, and 3, is described in evaluations dated June 22, 2000 (Reference 257) and June 28, 2007 (Reference 258). These evaluations concluded that the licensee's IPEEE process is capable of identifying the most likely severe accidents and severe accident vulnerabilities related to seismic, high winds, external floods, and nearby facilities/transportation accidents. All commitments resulting from the BFN IPEEE program have been adequately resolved. The impact of EPU implementation on external event risk (with the exception of internal fires) is evaluated using the insights and results from the Browns Ferry IPEEE submittal, as discussed in SE Section 2.13.1.4.

Internal Events PRA

As discussed in Sections 1.2.2, "Internal Events PRA," and A.1, "Internal Events PRA Technical Adequacy," of the LAR (Reference 1), Attachment 44 (Reference 54), the licensee's evaluation of the technical adequacy of the internal events PRA (IEPRA) model consisted of a full-scope peer review that was performed in May 2009 using the process under NEI 05-04, Revision 2 (Reference 259) and ASME/ANS PRA standard ASME/ANS RA-Sa-2009 (Reference 260), as qualified by RG 1.200, Revision 2 (Reference 261). A separate, similar review was performed for the internal flooding portion of the Browns Ferry PRA in September 2009. In July 2015, a focused-scope peer review evaluated specific changes made to the IEPRA (excluding internal flooding) and assessed some facts and observations (F&Os) from the previous peer review that were considered closed by the licensee's self-review.

For supporting requirements in the PRA standard, there are three degrees of "satisfaction" referred to as capability categories (i.e., I, II, and III), with I being the minimum, II considered widely acceptable, and III indicating the maximum achievable scope/level of detail, plant specificity, and realism. For many supporting requirements, the capability categories may be combined (e.g., the requirement for meeting Capability Category I may be combined with II), or the requirement may be the same across all capability categories so that the requirement is simply met or not met.

Table A-1, "Internal Events PRA F&O Resolution," of the LAR, Attachment 44 (Reference 54) provides the licensee's dispositions to 78 F&Os from both the internal events and internal flooding peer reviews, all of which are characterized in Table A-1 as findings per NEI 05-04 peer review guidelines. In general, an F&O is written for any supporting requirement that is judged not to be met or does not fully satisfy Capability Category II of the PRA standard and RG 1.200, Revision 2. Each F&O was dispositioned by either providing a description of how the F&O was resolved or providing an assessment of the impact of resolution of the F&O on the results for the EPU LAR application. The NRC staff evaluated each F&O and the licensee's disposition in Table A-1 to determine whether the F&O had any significant impact for the application.

In an RAI associated with IEPRA F&O 4-21 on the use of joint human error probabilities (HEPs), the NRC staff requested the licensee's justification with respect to the establishment of acceptable minimum (or "floor") values for HEP combinations. In its response dated April 27, 2016 (Reference 16), the licensee updated the EPU risk evaluation to apply a floor value of 1E-05 to all HEP combinations that do not include: (1) long-term decay heat removal (DHR) human failure events (HFEs) for CDF, or (2) those HFEs cued and guided by Severe Accident Mitigation Guideline (SAMG) procedures for LERF. For the remaining combinations, the licensee stated that the IEPRA applied a floor value of 1E-06 given that a low dependency exists between long-term DHR and SAMG actions and other earlier actions. These revised floor values were incorporated in a combined sensitivity analysis provided by the response, as discussed in Section 2.13.1.6 of this SE. The NRC staff concludes this issue is resolved, because the EPU risk evaluation considered the floor values consistent with guidance in NUREG-1792, "Good Practices for Implementing Human Reliability Analysis (HRA)" (Reference 262).

As a result of the review of information submitted by the licensee, the NRC staff concludes that the Browns Ferry IEPRA has sufficient technical adequacy and that its quantitative results, considered together with sensitivity study results, can be used to demonstrate that the change

in risk due to the EPU meets the acceptance guidelines of RG 1.174. To reach this conclusion, the NRC staff has reviewed all F&Os provided by the peer reviewers and determined that the resolution of every F&O supports the determination that the quantitative results are adequate or have no significant impact on the IEPRA.

Fire PRA

As discussed in Sections 1.2.3, "FPRA Quality," and A.2, "FPRA Technical Adequacy," of the LAR Attachment 44 (Reference 54), the licensee's evaluation of the technical adequacy of the FPRA model consisted of three peer reviews. A full-scope peer review was performed in January 2012. A focused-scope follow-on peer review was conducted in June 2012, and a final focused-scope peer review was conducted in May 2015. All peer reviews used the NEI 07-12 process (Reference 263) and PRA standard ASME/ANS RA-Sa-2009, as qualified by RG 1.200, Revision 2. The full-scope peer review examined all of the technical elements of the Browns Ferry FPRA against all technical elements in Part 4 of ASME/ANS RA-Sa-2009. The 2012 focused-scope follow-on peer review performed a review against a list of SRs that were selected based on the FPRA model changes implemented subsequent to the full-scope peer review. The 2015 focused-scope peer review evaluated specific changes made to the FPRA and assessed the F&Os from the previous two peer reviews that were considered closed by the licensee's self-review.

The NRC staff reviewed the safety evaluation associated with the licensee's LAR to transition to NFPA 805 (Reference 160) to identify any issues related to the technical adequacy of the FPRA that could impact the EPU application. In response to a staff RAI, the licensee clarified that the EPU FPRA incorporates the modeling changes in the composite analysis discussed in the response to a staff RAI associated with the licensee's LAR to transition to NFPA 805 and that these modeling changes were peer reviewed during the 2015 focused-scope peer review. The finding level F&Os from the peer reviews that remain open are listed and dispositioned in Table A-2, "BFN FPRA Open Peer Review Findings," of LAR Attachment 44 (Reference 54). Each F&O was dispositioned by either providing a description of how the F&O was resolved or providing an assessment of the impact of resolution of the F&O on the results for the EPU LAR application. The NRC staff evaluated each F&O and the licensee's disposition in Table A-2 to determine whether the F&O had any significant impact for the application. The NRC staff finds that all F&Os were properly assessed and dispositioned in regard to this application.

As a result of the review of the LAR and responses to RAIs, the NRC staff concludes that the Browns Ferry FPRA has sufficient technical adequacy and that its quantitative results, considered together with sensitivity study results, can be used to demonstrate that the change in risk due to the EPU meets the acceptance guidelines of RG 1.174. To reach this conclusion, the NRC staff has reviewed all F&Os provided by the peer reviewers and determined that the resolution of every F&O supports the determination that the quantitative results are adequate or have no significant impact on the FPRA.

Conclusions Regarding the Quality of the BFN PRA

The quality of a 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. As noted above, the LAR stated that several peer reviews were conducted on the BFN IEPRA (including internal flooding) and FPRA models. The NRC staff reviewed the findings associated with the

peer reviews and the associated dispositions. Based on its evaluation and the responses to RAIs, the NRC staff finds that the BFN IEPRA and FPRA models used to support the risk evaluation for this application have sufficient scope, level of detail, and technical adequacy to support the evaluation of the EPU.

2.13.1.2 Internal Events Risk Evaluation

The licensee reviewed the PRA elements for the IEPRA to identify potential effects associated with the EPU. The NRC staff's evaluation of this review is provided below.

Initiating Event Frequencies

The Browns Ferry IEPRA model includes the following initiating event categories: transients including LOOP, inadvertent opening of one safety relief valve (SRV), LOCA, support system failures, internal flooding, and interfacing systems LOCA (ISLOCA). The licensee's assessment of the impact on these initiating events due to the Browns Ferry EPU is discussed below.

- Transients – Evaluation of the plant changes and procedural changes for EPU conditions do not result in any new transient initiators, nor directly impact transient initiator frequencies. Sensitivity analyses were performed that increased the transient initiator frequencies to bound the various changes to the balance of plant (BOP) side of the plant, such as the main turbine modifications. Section 2.13.1.6 of this SE discusses the sensitivity analyses.

- LOOP – No changes to the LOOP initiating event frequency for the EPU is expected, because the isophase bus duct cooling system was modified to accommodate the additional power output and there is no significant impact on grid stability due to the EPU, as discussed in Browns Ferry EPU LAR Attachment 43, "Transmission System Stability Evaluation," Revision 4 (Critical Energy Infrastructure Information), Enclosure 2 of TVA letter dated January 20, 2017 (Reference 39).

- Inadvertent Opening of One SRV (IOOV) – No change to the reactor pressure vessel (RPV) operating pressure is planned in support of the EPU. Therefore, no impact on IOOV frequency due to the EPU is postulated. It should be noted that the probability of an SRV to fail to reclose at EPU conditions is increased, because it is assumed that the SRVs may be demanded more frequently resulting in an SRV failing to reclose.

- LOCA – No change to RPV operating pressure, inspection frequencies, or primary water chemistry are planned in support of the EPU. Therefore, no impact on LOCA frequencies due to the EPU are postulated. Acknowledging that increased flow rates of the EPU can result in increased piping erosion/corrosion rates, sensitivity analyses were performed that increased the LOCA initiating event frequencies including main steam and feedwater line break. Section 2.13.1.6 of this SE discusses the sensitivity analyses.

- Support System Failures – No significant changes to support systems are planned in support of the EPU. Therefore, 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 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 the EPU could have an impact on some of the internal flooding initiating event frequencies, a separate sensitivity evaluation was performed, which conservatively increased all of the internal flood frequencies, and showed a non-significant change to the calculated risk results.

- ISLOCA – The LAR stated that no planned modifications as part of the EPU have been identified that expose low pressure piping to high pressure. Therefore, no impact on the ISLOCA frequencies due to the EPU is postulated.

Based on its review, the NRC staff finds that the licensee adequately addressed the impact of the proposed EPU on initiating event frequencies and concludes that they should not be noticeably impacted by the proposed EPU. Furthermore, sensitivity analyses that increase transient, LOCA, and internal flooding initiating event frequencies are quantified in the EPU risk analysis to bound the various changes to the plant and potential operational issues. These sensitivity analyses are discussed in Section 2.13.1.6 of this SE. Lastly, the NRC staff notes that changes in the initiating event frequencies following implementation of the proposed EPU would be adequately identified and tracked under the licensee's existing performance monitoring programs and processes.

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 with enhanced like components or an upgrade of existing components. The licensee described no planned operational modifications as part of the EPU that involve operating equipment beyond design ratings. It should be noted that the probability of a stuck open relief valve was increased to address a higher likelihood of this failure mode in the EPU model due to an increase in the number or duration of SRV actuations during a transient initiator.

Based on its review, the NRC staff finds that the licensee adequately addressed the impact of the proposed EPU on equipment reliability. 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 NRC staff notes that the licensee's component monitoring programs, including equipment modifications and/or replacement support the continued reliability of the equipment.

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 Browns Ferry PRA by 14.3 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.

The EPU results in slight changes to the timing in the accident progression for the Level 1 IEPRA and can impact 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.

Based on its review, the NRC staff finds that the licensee adequately addressed the impact of the proposed EPU on success criteria.

System Modeling

The licensee evaluated the impact of the proposed EPU on the IEPRA system modeling (i.e., fault trees). Browns Ferry plant changes associated with the EPU do not result in the need to change any system models credited in the IEPRA. The only exception involves a Unit 3 modification (Design Change Notice 51052) in Attachment 47, "List and Status of Plant Modifications," of the EPU LAR. This modification changes the electrical configuration for 4kV Unit Board 3C. The modification requires a manual transfer for the alternate power to the board during some unique power alignments created during maintenance activities. A sensitivity analysis was performed that shows this modification had an insignificant impact on the PRA results. The emergency high pressure make-up (EHPM) system is a new system being installed as an NFPA 805 modification to provide an independent and diverse injection system to supplement the existing injection systems. However, the IEPRA conservatively does not credited this system.

Based on its review, the NRC staff finds that the licensee adequately addressed the impact of the proposed EPU on system modeling.

Operator Actions and LOOP Recovery

The change in HEPs as a result of the proposed EPU drives the change in risk results for this application; therefore, it is important that the calculated changes in HEPs as a result of the EPU are realistic. Based on the discussion in Section 4.1.6, "Human Error Probabilities," in Attachment 44 (Reference 54) of the EPU LAR, as supplemented by the response dated

April 27, 2016 (Reference 16), to the NRC RAI, the higher decay heat level from the EPU normally results in reduced time available within which to detect, diagnose, execute required actions, and perform needed recovery 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 evaluated for potential impact from the EPU and re-calculated, as necessary, using the same human reliability analysis (HRA) methods. All updated HEP values are factored directly into the risk assessment. In order to confirm the reasonableness of these updated HEP values, the NRC staff requested that the licensee explain in more detail how several HEPs were quantified for both the EPU and CLTP cases. In its responses by letters dated April 27, 2016 (Reference 16) and August 3, 2016 (Reference 32) to these RAIs, the licensee provided detailed HRA calculation sheets for the associated HFEs for both the CLTP and EPU cases and explained how recoveries were represented in the HFE's cognitive analysis and execution analysis such that the HEPs were realistically estimated for the CLTP and EPU cases. The difference in HEPs between the CLTP and EPU cases is primarily due to the timing difference from the MAAP runs for the two cases and the impact that has on the cognitive portion of the HEPs and on the dependency level for the recovery actions. 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.

In Section 4.1.3, "Accident Sequences," in Attachment 44 (Reference 54) of the EPU LAR, the licensee used a simplified approach for LOOP recovery based on early recovery or late recovery of offsite power (i.e., 30 minutes or 4 hours). The licensee concluded that the change in reactor power as a result of the EPU would not impact the LOOP recovery probabilities. However, it was not clear to the NRC staff why the change in reactor power does not impact the LOOP recovery probabilities since higher power levels normally result in reduced time available to recover power before core damage occurs. In response to the staff RAI, the licensee described the simplified approach for LOOP recovery and justified why the change in power due to the EPU does not impact LOOP recovery probabilities. Based on this response, there are two times of interest with respect to recovery of offsite power: (1) approximately 30 minutes after LOOP with failure of all injection sources (i.e., time to core uncovery), and (2) 4 hours after the LOOP with success of an injection source (i.e., expected battery life of injection source). It is assumed that there is no power available from the diesel generators for the duration of the LOOP, which gives a conservative time to core damage. Because battery life is unaffected by the EPU, this recovery probability remains the same between the CLTP and EPU. The time to core uncovery during a LOOP with failure of all injection sources is calculated to be 32 minutes under the CLTP and 30 minutes under the EPU. This time reflects the minimum amount of time available to recover offsite power. The estimated probabilities that the LOOP will not be recovered within 30 minutes and 32 minutes for EPU and CLTP operations, respectively, were determined from the LOOP 2010 Summary Update to NUREG/CR-6890 (Reference 264). The licensee showed that the impact of the two-minute difference in uncovery time between CLTP and EPU power levels has an insignificant impact on risk.

Based on its review, the NRC staff finds that the licensee adequately addressed the impact of the proposed EPU on operator actions and LOOP recovery.

Conclusions Regarding Internal Events Risk Evaluation

The NRC staff has reviewed the licensee's assessment of the internal events risk associated with the implementation of the proposed EPU and concludes that the licensee has adequately

addressed the potential impacts associated with the implementation of the proposed EPU. The NRC staff further concludes that the results of the licensee's internal events risk analysis indicate that the risks associated with the proposed EPU are acceptable. Therefore, the NRC staff finds the risk implications of the proposed EPU acceptable.

2.13.1.3 Fire Risk Evaluation

The licensee reviewed the PRA elements specifically related to the FPRA to identify potential effects associated with the EPU. The NRC staff's evaluation of this review is provided below.

Fire Initiating Event Frequencies

The licensee evaluated the impact of the proposed EPU on fire scenario frequencies and concluded that no new fire scenarios or significant impacts to existing fire scenario frequencies are anticipated due to EPU. Therefore, no change was made to the fire scenario frequencies.

Based on its review, the NRC staff finds that the licensee adequately addressed the impact of the proposed EPU on fire scenario frequencies and concludes that they should not be noticeably impacted by the proposed EPU. Furthermore, a sensitivity study that increased severity factors to reflect increased fire scenario frequencies are quantified in the EPU risk analysis to bound the various changes to the plant (e.g., some large pumps may be drawing more power after the EPU, potentially larger lubricating oil reservoirs could sustain larger fires). This sensitivity study showed that any changes in fire scenario frequencies as a result of the EPU will have a negligible effect on the risk results.

Fire-Induced Accident Sequences

The licensee evaluated the impact of the proposed EPU on fire-induced accident sequences. The EPU does not change the plant configuration or operation in a manner to introduce new fire-induced accident sequences or changes to existing fire-induced accident progressions for the FPRA. The EPU results in slight changes to the timing in the accident progression for the Level 1 FPRA and can impact HEPs for operator actions. This change has been factored into the revised HEP values for EPU conditions, as described below in the section on operator actions.

Based its review, the NRC staff finds that the licensee adequately addressed the impact of the proposed EPU on fire-induced accident sequences.

System Modeling

The licensee evaluated the impact of the proposed EPU on the FPRA system modeling (i.e., fault trees). BFN plant changes associated with the EPU do not result in the need to change any system models credited in the FPRA. The only exception involves a Unit 3 modification (Design Change Notice 51052) in Attachment 47 of the EPU LAR. This modification changes the electrical configuration for 4kV Unit Board 3C. The modification requires a manual transfer for the alternate power to the board during some unique power alignments created during maintenance activities. However, a sensitivity analysis was performed that shows this modification had an insignificant impact on the PRA results. The EHPM is a new system being installed as an NFPA 805 modification to provide an independent

and diverse injection system to supplement the existing injection systems. This system is modeled the same in the CLTP and EPU FPRA analyses, which is acceptable.

Based on its review, the NRC staff finds that the licensee adequately addressed the impact of the proposed EPU on system modeling.

Operator Actions

Based on the discussion in Section 4.2.4, "Post Fire Human Error Probabilities," in Attachment 44 (Reference 54) of the EPU LAR, as supplemented by the licensee's response dated April 27, 2016 (Reference 16) to the NRC staff's RAI, the licensee evaluated the impact of the proposed EPU on HFEs of the FPRA. The higher decay heat level from the EPU would normally result in reduced time available within which to detect, diagnose, execute required actions, and perform needed recovery actions. The licensee performed MAAP calculations to determine how the operator action timelines were impacted. Afterwards, all post-initiator HEPs in the model were evaluated for potential impact from EPU and re-calculated, as necessary, using the same HRA methods. All updated HEP values are factored directly into the risk assessment. In order to confirm the reasonableness of these updated HEP values, the NRC staff requested that the licensee explain in more detail how several HEPs were quantified for both the EPU and CLTP cases.

Conclusions Regarding Fire Risk Evaluation

Based on the discussion provided above, the NRC staff has not identified any issues associated with the licensee's fire risk evaluation that would significantly alter the overall risk results or conclusions for this LAR. Therefore, the NRC staff concludes that the licensee's fire risk evaluation is acceptable.

2.13.1.4 Seismic and Other External Events Risk Evaluation

Browns Ferry does not have a seismic PRA and the IPEEE study used a seismic margin analysis methodology (Reference 255) that does not predict a numerical risk result. As such, the seismic CDF was developed using a bounding assessment rather than a PRA. High winds/tornadoes, external flooding, and transportation and nearby facility accidents were addressed by reviewing the plant environs against regulatory requirements. The licensee's risk assessment of the impact of EPU implementation on seismic and other external events risk is discussed below.

Seismic Risk

The original Browns Ferry seismic risk analysis was performed as part of the IPEEE. The Units 2 and 3 seismic IPEEE submittal identified items for seismic margin improvement. The Unit 1 seismic IPEEE submittal identified outliers associated with the BFN Unit 1 USI A-46 screening evaluations (Reference 265). The LAR stated that these identified vulnerabilities and outliers have all been addressed and corrected through the corrective action program and further reduce the seismic risk.

The EPU results in additional thermal energy stored in the 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 seismic margin analysis. The decrease in time available for operator actions, and

the associated increases in calculated HEPs is judged not to have a significant impact on seismic-induced risk, because seismic PRAs for Boiling Water Reactors (e.g., NUREG-1150 study, (Reference 266)) have shown that seismic risk is dominated by seismic-induced failures of systems, structures, and components. As such, the NRC staff does not expect the seismic risk associated with the EPU to significantly increase due to seismicity and create the "special circumstances" described in Appendix D of SRP Chapter 19.2.

The licensee explains in Section 5.4, "Seismic Risk," of Attachment 44 (Reference 54) to the EPU LAR, as supplemented by the response to the staff RAI, that the seismic CDF estimates were developed using the "weakest link model," and considered bounding, in the NRC staff's safety/risk assessment results for Generic Issue 199, "Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States on Existing Plants" (Reference 267).

Other External Events Risk

Browns Ferry does not have a PRA analysis for "other" external events (i.e., high winds/tornadoes, external flooding, and transportation and nearby facility accidents). The licensee evaluated these risks using its IPEEE study discussed in Section 2.13.1.1 of this SE. For external flooding, transportation and nearby facility accidents, the licensee reviewed the plant environs against regulatory requirements regarding these hazards (i.e., NRC SRP 1975 criteria (Reference 256)). The licensee concluded that Browns Ferry meets the applicable NRC SRP 1975 criteria, and, therefore, has an acceptably low risk with respect to these hazards. Since Browns Ferry does not meet the NRC SRP 1975 criteria for high winds/tornadoes, a bounding analysis was performed in the IPEEE and showed the contribution to CDF due to high winds/tornadoes to also be acceptably low.

Conclusions Regarding Seismic and Other External Events Risk Evaluation

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 the EPU LAR. Therefore, the NRC staff concludes that there are no issues with the external events risk evaluation and that the risk impact from external events resulting from the proposed EPU will be very small, based on the licensee's risk evaluation.

2.13.1.5 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 LAR stated that computerized risk monitors (i.e., Equipment Out of Service computer program) and site-specific shutdown risk management guidelines are in place to ensure the risk impacts of the EPU on shutdown operations are not significant and that requirements of NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management"

(Reference 268) are implemented to assure risk is assessed and that structures, systems, and components that perform key safety functions are available when needed.

During a LOOP event with failure of all injection sources (e.g., a station blackout), the EPU results in a reduced time to restore offsite power before core damage due to boil off, which potentially results in an increase in offsite power recovery failure probability. The licensee's submittal, as supplemented by its response dated August 3, 2016 (Reference 32), to the staff's RAI, shows the estimated times to core damage for both the CLTP and the EPU, which are based on different initial RPV water levels for a LOOP event with failure of all injection sources. These estimated times to core damage trend upward the longer the outage lasts. From the review of the potential impacts on initiating events, success criteria, and HRA, the EPU is assessed to have a negligible impact on shutdown risk. Based on the results in the response to APLA-RAI 04, the licensee approximates a 1 percent increase in shutdown CDF due to the EPU.

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 the shutdown operations risk evaluation is acceptable and that the impact on shutdown risk resulting from the proposed EPU will be negligible, based on the licensee's shutdown risk management process.

2.13.1.6 Risk Impacts of EPU

The following table summarizes the results of the licensee's risk evaluation as discussed in Section 5.6, "Total Risk," of Attachment 44 (Reference 54) to the EPU LAR:

Total CDF and LERF Risk Metrics

	CLTP (per year)	EPU (per year)	Change in Risk (per year)
Unit 1 CDF	5.91E-05	6.08E-05	1.69E-06
Unit 1 LERF	7.96E-06	8.73E-06	7.74E-07
Unit 2 CDF	5.96E-05	6.14E-05	1.74E-06
Unit 2 LERF	7.99E-06	8.65E-06	6.63E-07
Unit 3 CDF	6.47E-05	6.64E-05	1.67E-06
Unit 3 LERF	7.18E-06	7.72E-06	5.45E-07

The increases in total CDF and LERF, shown in the above table, fall within the RG 1.174 acceptance guidelines for being "small," and, therefore, do not raise concerns of adequate protection.

In Section 5.7, "Sensitivity Analysis and Uncertainties," of Attachment 44 (Reference 54) to the EPU LAR, as supplemented by its response (Reference 16) to a staff RAI, the licensee evaluated key sources of uncertainty and sensitivity for the IEPRA and FPRA. In response to another RAI, the licensee performed a sensitivity analysis that considers the combined effects from the impact of EPU conditions, including:

- Combined impacts from sensitivity analyses in Sections 5.7.1.4 and 5.7.1.6 of LAR Attachment 44 on the IEPRA's transient and LOCA initiating event frequencies,

- Use of minimum joint HEP values consistent with the approach used for the FPRA that the NRC staff found acceptable (Reference 160), and

- Assessment of mean risk values (for both the internal events risk and fire risk) where the state-of-knowledge correlation can be important.

For the combined sensitivity analysis, the risk acceptance guidelines of RG 1.174 are met for total risk and total change in risk. However, the total LERF for BFN Unit 1 reaches the RG 1.174 acceptance guideline threshold of 1E-05/year, and the total LERF of BFN Unit 2 is close to, but less than that threshold. These numerical estimates contain significant conservatisms, such as the IEPRA does not credit the EHPM pump, which is to be installed as an NFPA 805 modification to provide an independent and diverse injection system to supplement the existing injection systems. If the EHPM pump were credited in the IEPRA, the CDF and LERF would decrease significantly.

The NRC staff finds the licensee's evaluation of the impact of the proposed EPU on risk from internal events, fire, seismic, shutdown, and other external events is reasonable. The NRC staff concludes that the base risk due to the proposed EPU is acceptable and that the licensee provided adequate protection which meets the currently specified regulatory requirements.

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 risk 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 RENEWED FACILITY OPERATING LICENSE AND TECHNICAL SPECIFICATION CHANGES

3.1 Changes to Renewed Facility Operating License (RFOL)

To achieve the EPU, the following changes were proposed by the licensee or requested by the NRC staff to the Renewed Facility Operating License (RFOL) for BFN, Units 1, 2, and 3.

3.1.1 Change in Power Level

The licensee proposed, in Attachment 2, "Proposed Technical Specification," of the EPU LAR dated September 21, 2015 (Reference 1), to revise paragraph 2.C(1) of RFOL Nos. DPR-33, DPR-52, and DPR-68 for BFN Units 1, 2, and 3, respectively, to increase the maximum reactor core power from 3458 MWt to 3952 MWt. The revised License Condition 2.C.(1) states:

> The licensee is authorized to operate the facility at steady state reactor core power levels not in excess of 3,952 megawatts thermal.

This change reflects the proposed approximate 14.3 percent increase in thermal power and is consistent with the licensee's supporting safety analyses. Therefore, the NRC staff concludes that the proposed change to RFOL 2.C(1) is acceptable.

3.1.2 Change to Transition License Condition Regarding to NFPA 805

The licensee proposed, in Enclosure 4 of its letter dated October 31, 2016 (Reference 38), an update to Item 49 in Table S-3, "Implementation," of TVA letter dated October 20, 2015 (Reference 189). Table S-3 is incorporated by reference in current license conditions 2.C.(13), 2.C.(14), and 2.C.(7), Transition License Condition 3 for BFN Units 1, 2, and 3, respectively. Therefore, the licensee in Enclosure 2 proposed to replace a reference to the October 20, 2015, letter with a reference to the October 31, 2016, letter in the above license conditions for all BFN units. The revised Transition License Condition 3 under license conditions 2.C.(13), 2.C.(14), and 2.C.(7) states:

> The licensee shall complete the implementation items as listed in Table S-3, "Implementation Items," of Tennessee Valley Authority letters CNL-15-191, dated September 8, 2015, and CNL-16-165, dated October 31, 2016, within 240 days after issuance of the license amendment unless that date falls within a scheduled refueling outage, then implementation will occur within 60 days after startup from that scheduled refueling outage. Implementation items 32 and 33 are associated with modifications and will be completed after all procedure updates, modifications, and training are complete.

The NRC staff finds the proposed change acceptable, since it is consistent with the licensee's proposed changes and the NRC staff's review as discussed in Section 2.6 of this SE.

3.1.3 Potential Adverse Flow Effect

The licensee proposed, in Enclosure 2 of its letter dated October 31, 2016 (Reference 38), to add license conditions 2.C.(18) for Units 1 and 2, and license condition 2.C.(14) for Unit 3. The licensee stated that the proposed change provides requirements for monitoring and evaluating potential adverse flow effects as a result of power uprate operation, including verifying the continued structural integrity of the replacement steam dryers. Also, during the first two scheduled refueling outages after reaching EPU conditions, requirements are provided for performing visual inspections of the replacement steam dryers. The proposed license conditions 2.C.(18) for Units 1 and 2, and 2.C.(14) for Unit 3 are provided in the following sections. These license conditions are addressed in Section 2.2.6 of this SE.

Unit 1 License condition 2.C.(18)

(18) Potential Adverse Flow Effects

> 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) for initial power ascension from 3458 MWt to the extended power uprate (EPU) power level of 3952 MWt.

(a) The following requirements are placed on operation of the facility before and during the initial power ascension:

1. TVA shall provide a Power Ascension Test (PAT) Plan for the BFN Unit 1 steam dryer testing. The PAT plan shall be submitted to the NRC Project Manager no later than 10 days before start-up

2. TVA shall monitor the main steam line (MSL) strain gauges at a minimum of three power levels up to 3458 MWt. If the number of active MSL strain gauges is less than two strain gauges (180 degrees apart) at any of the eight MSL locations, TVA will stop power ascension and repair/replace the damaged strain gauges and only then resume power ascension.

3. At least 90 days prior to the start of the BFN Unit 1 EPU outage, TVA shall revise the BFN Unit 1 replacement steam dryer (RSD) analysis utilizing the BFN Unit 3 on-dryer strain gauge based end-to-end bias and uncertainties (B&Us) at EPU conditions, and submit the information including the updated limit curves and a list of dominant frequencies for BFN Unit 1, to the NRC as a report in accordance with 10 CFR 50.4.

   a. If the on-dryer instrumentation was not available when BFN Unit 3 reached a power level of 3458 MWt and the BFN-specific bias and uncertainty data and transfer function could not be developed, the predicted dryer loads during the BFN Unit 1 power ascension will be calculated with the Plant Based Load Evaluation Method 2 transfer function used in the steam dryer design analyses for EPU. The acceptance limits will be based on BFN Unit 3 steam dryer confirmatory stress analysis results using the MSL strain gauge data collected at EPU conditions. The acceptance limits will ensure the steam dryer stress margins remain above the minimum alternating stress ratio (MASR) determined in the BFN Unit 3 steam dryer EPU confirmatory analyses.

4. TVA shall evaluate the BFN Unit 1 limit curves prepared in item (a)3 above based on new MSL strain gauge data collected following the BFN Unit 1 EPU outage at or near 3458 MWt. If the limit curves change, the new post-EPU outage limit curves shall be provided to the NRC Project Manager. TVA shall not increase power above 3458 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.

5. TVA shall monitor the MSL strain gauges during power ascension above 3458 MWt for increasing pressure fluctuations in the steam lines. Upon the initial increase of power above 3458 MWt until reaching 3952 MWt, TVA shall collect data from the MSL strain gauges at nominal 2.5 percent of 3458 MWt (approximately 86 MWt) increments and evaluate steam dryer performance based on this data.

6. During power ascension at each nominal 2.5 percent power level above 3458 MWt (approximately 86 MWt), TVA shall compare the MSL data to the approved

limit curves based on end-to-end B&Us from the BFN Unit 3 benchmarking at EPU conditions and determine the MASR.

7. TVA shall hold the facility at approximately 3630 MWt and 3803 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.

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

   d. Evaluate the measured vibration data (collected in Item 7.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, to the NRC Project Manager, upon completion of the evaluation for each of the hold points.

   f. TVA 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.

8. If any frequency peak from the MSL strain gauge data exceeds the Level 1 limit curves, TVA shall return the facility to a power level at which the limit curve is not exceeded. TVA shall resolve the discrepancy, evaluate and document the continued structural integrity of the steam dryer, and provide that documentation to the NRC Project Manager prior to further increases in reactor power. If a revised stress analysis is performed and new limit curves are developed, then TVA 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 Item (b)1 below.

(b) TVA shall implement the following actions for the initial power ascension from 3458 MWt to 3952 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 3458 MWt, TVA 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 Item (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 BFN Unit 3 EPU measurements.

b. Use of scaling factors associated with all of the SRV acoustic resonances as estimated in the predictive analysis or in-plant data acquired during power ascension.

2. After reaching 3952 MWt, TVA shall obtain measurements from the MSL strain gauges and establish the steam dryer flow-induced vibration load fatigue margin for the facility and update the steam dryer stress report. These data will be provided to the NRC staff as described below in item (e).

(c) TVA shall prepare the EPU PAT Plan to include the following.

1. The MSL strain gauge limit curves to be applied for evaluating steam dryer performance, based on end-to-end B&Us from BFN Unit 3 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 3458 MWt.

10. Identify the NRC Project Manager as the NRC point of contact for providing PAT plan information during power ascension.

11. Methodology for updating limit curves.

(d) The following key attributes of the PAT Plan shall not be made less restrictive without prior NRC approval:

1. During initial power ascension testing above 3458 MWt, each of the two hold points shall be at increments of approximately 5 percent of 3458 MWt.

2. Level 1 performance criteria.

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

Changes to other aspects of the PAT Plan may be made in accordance with the guidance of NEI 99-04, "Guidelines for Managing NRC Commitments," issued July 1999.

(e) Following the data collection and evaluation at the EPU power level, TVA shall provide 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 BFN Unit 3 benchmarking at EPU conditions. The report shall be submitted to NRC within 90 days of the completion of EPU power ascension testing for BFN Unit 1. Should the results of this stress analysis indicate the allowable stress in any part of the steam dryer is exceeded, TVA shall reduce power to a level at which the allowable stress is met, evaluate the steam dryer integrity, and assess any shortcomings in the predictive analysis. The results of this evaluation, including a recommended resolution of any identified issues and a demonstration of steam dryer integrity at EPU conditions, shall be provided to the NRC for review and approval prior to return to EPU conditions.

(f) Following the data collection and evaluation at the EPU power level, TVA shall provide a vibration summary report to the NRC. The summary report shall be submitted to the NRC within 90 days of the completion of EPU power ascension testing for BFN Unit 1. The vibration summary report shall include the information in items (f)1 through (f)3, as follows:

1. Vibration data for piping and valve locations deemed prone to vibration and vibration monitoring locations identified in Attachment 45 to the EPU application dated September 21, 2015, including the identified locations associated with MSLs, feedwater lines, safety relief valves and the main steam isolation valves.

2. An evaluation of the measured vibration data collected in item (f)1 above compared against acceptance limits.

3. Vibration values and associated acceptance limits at approximately 3630 MWt, 3803 MWt, and 3952 MWt using the data collected in item (f)1, above.

(g) 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 Boiling Water Reactor Vessels and Internals Project (BWRVIP)-139A (Steam Dryer Inspection and Flaw Evaluation Guidelines) and General Electric (GE) inspection guidelines (SIL 644, BWR Steam Dryer Integrity).

(h) 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 to the NRC within 90 days following startup from each of the first two respective refueling outages.

(i) 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 items (g) and (h), 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 Item (i).

Unit 2 License condition 2.C.(18)

(18) Potential Adverse Flow Effects

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) for initial power ascension from 3458 MWt to the extended power uprate (EPU) power level of 3952 MWt.

(a) The following requirements are placed on operation of the facility before and during the initial power ascension:

1. TVA shall provide a Power Ascension Test (PAT) Plan for the BFN Unit 2 steam dryer testing. The PAT plan shall be submitted to the NRC Project Manager no later than 10 days before start-up

2. TVA shall monitor the main steam line (MSL) strain gauges at a minimum of three power levels up to 3458 MWt. If the number of active MSL strain gauges is less than two strain gauges (180 degrees apart) at any of the eight MSL locations, TVA will stop power ascension and repair/replace the damaged strain gauges and only then resume power ascension.

3. At least 90 days prior to the start of the BFN Unit 2 EPU outage, TVA shall revise the BFN Unit 2 replacement steam dryer (RSD) analysis utilizing the BFN Unit 3 on-dryer strain gauge based end-to-end bias and uncertainties (B&Us) at EPU conditions, and submit the information including the updated limit curves and a list of dominant frequencies for BFN Unit 2, to the NRC as a report in accordance with 10 CFR 50.4.

   a. If the on-dryer instrumentation was not available when BFN Unit 3 reached a power level of 3458 MWt and the BFN-specific bias and uncertainty data and transfer function could not be developed, the predicted dryer loads during the BFN Unit 2 power ascension will be calculated with the Plant Based Load Evaluation Method 2 transfer function used in the steam dryer design analyses for EPU. The acceptance limits will be based on BFN Unit 3 steam dryer confirmatory stress analysis results using the MSL strain gauge data collected at EPU conditions. The acceptance limits will ensure the steam dryer stress margins remain above the minimum alternating stress ratio

(MASR) determined in the BFN Unit 3 steam dryer EPU confirmatory analyses.

4. TVA shall evaluate the BFN Unit 2 limit curves prepared in item (a)3 above based on new MSL strain gauge data collected following the BFN Unit 2 EPU outage at or near 3458 MWt. If the limit curves change, the new post-EPU outage limit curves shall be provided to the NRC Project Manager. TVA shall not increase power above 3458 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.

5. TVA shall monitor the MSL strain gauges during power ascension above 3458 MWt for increasing pressure fluctuations in the steam lines. Upon the initial increase of power above 3458 MWt until reaching 3952 MWt, TVA shall collect data from the MSL strain gauges at nominal 2.5 percent of 3458 MWt (approximately 86 MWt) increments and evaluate steam dryer performance based on this data.

6. During power ascension at each nominal 2.5 percent power level above 3458 MWt (approximately 86 MWt), TVA shall compare the MSL data to the approved limit curves based on end-to-end B&Us from the BFN Unit 3 benchmarking at EPU conditions and determine the MASR.

7. TVA shall hold the facility at approximately 3630 MWt and 3803 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.

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

   d. Evaluate the measured vibration data (collected in item 7.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, to the NRC Project Manager, upon completion of the evaluation for each of the hold points.

   f. TVA 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.

8. If any frequency peak from the MSL strain gauge data exceeds the Level 1 limit curves, TVA shall return the facility to a power level at which the limit curve is not exceeded. TVA shall resolve the discrepancy, evaluate and document the

continued structural integrity of the steam dryer, and provide that documentation to the NRC Project Manager prior to further increases in reactor power. If a revised stress analysis is performed and new limit curves are developed, then TVA 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 Item (b)1 below.

(b) TVA shall implement the following actions for the initial power ascension from 3458 MWt to 3952 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 3458 MWt, TVA 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 item (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 BFN Unit 3 EPU measurements.

   b. Use of scaling factors associated with all of the SRV acoustic resonances as estimated in the predictive analysis or in-plant data acquired during power ascension.

2. After reaching 3952 MWt, TVA shall obtain measurements from the MSL strain gauges and establish the steam dryer flow-induced vibration load fatigue margin for the facility and update the steam dryer stress report. These data will be provided to the NRC staff as described below in item (e).

(c) TVA shall prepare the EPU PAT Plan to include the following.

1. The MSL strain gauge limit curves to be applied for evaluating steam dryer performance, based on end-to-end B&Us from BFN Unit 3 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 3458 MWt.

10. Identify the NRC Project Manager as the NRC point of contact for providing PAT plan information during power ascension.

11. Methodology for updating limit curves.

(d) The following key attributes of the PAT Plan shall not be made less restrictive without prior NRC approval:

1. During initial power ascension testing above 3458 MWt, each of the two hold points shall be at increments of approximately 5 percent of 3458 MWt.

2. Level 1 performance criteria.

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

Changes to other aspects of the PAT Plan may be made in accordance with the guidance of NEI 99-04, "Guidelines for Managing NRC Commitments," issued July 1999.

(e) Following the data collection and evaluation at the EPU power level, TVA shall provide 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 BFN Unit 3 benchmarking at EPU conditions. The report shall be submitted to the NRC within 90 days of the completion of EPU power ascension testing for BFN Unit 2. Should the results of this stress analysis indicate the allowable stress in any part of the steam dryer is exceeded, TVA shall reduce power to a level at which the allowable stress is met, evaluate the steam dryer integrity, and assess any shortcomings in the predictive analysis. The results of this evaluation, including a recommended resolution of any identified issues and a demonstration of steam dryer integrity at EPU conditions, shall be provided to the NRC for review and approval prior to return to EPU conditions.

(f) Following the data collection and evaluation at the EPU power level, TVA shall provide a vibration summary report to the NRC. The summary report shall be submitted to the NRC within 90 days of the completion of EPU power ascension testing for BFN Unit 2. The vibration summary report shall include the information in items (f)1 through (f)3, as follows:

1. Vibration data for piping and valve locations deemed prone to vibration and vibration monitoring locations identified in Attachment 45 to the EPU application

dated September 21, 2015, including the identified locations associated with MSLs, feedwater lines, safety relief valves and the main steam isolation valves.

2. An evaluation of the measured vibration data collected in item (f)1 above compared against acceptance limits.

3. Vibration values and associated acceptance limits at approximately 3,630 MWt, 3,803 MWt, and 3952 MWt using the data collected in item (f)1, above.

(g) 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 Boiling Water Reactor Vessels and Internals Project (BWRVIP)-139A (Steam Dryer Inspection and Flaw Evaluation Guidelines) and (General Electric) GE inspection guidelines (SIL 644, BWR Steam Dryer Integrity).

(h) 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 to the NRC within 90 days following startup from each of the first two respective refueling outages.

(i) 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 items (g) and (h), 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 Item (i).

Unit 3 License condition 2.C.(14)

(14) Potential Adverse Flow Effects

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) for initial power ascension from 3458 MWt to the extended power uprate (EPU) power level of 3952 MWt.

(a) The following requirements are placed on operation of the facility before and during the initial power ascension to 3458 MWt:

1. TVA shall provide a Power Ascension Test (PAT) Plan for the BFN Unit 3 steam dryer testing. This plan shall include:

   a. Criteria for comparison and evaluation of projected strain and acceleration with on-dryer instrument data.

b. Acceptance limits developed for each on-dryer strain gauge.

c. Tables of predicted dryer stresses at a power level of 3458 MWt, strain amplitudes and power spectral densities (PSDs) at strain gauge locations, and maximum stresses and locations.

The PAT plan shall provide correlations between measured strains and the corresponding maximum stresses. The PAT plan shall be submitted to the NRC Project Manager no later than 10 days before start-up.

2. TVA shall monitor the main steam line (MSL) strain gauges and on-dryer instrumentation at a minimum of three power levels up to 3458 MWt. Based on a comparison of projected and measured strains and accelerations, BFN will assess whether the dryer acoustic and structural models have adequately captured the response significant to peak stress projections. If the measured strains and accelerations are not within the 3458 MWt acceptance limits, the new measured data will be used to re-perform the full structural re-analysis for the purposes of generating modified EPU acceptance limits.

   a. If the on-dryer instrumentation is unavailable, the BFN Unit 3 power ascension will be monitored using the available MSL strain gauges. The predicted dryer loads during the power ascension will be calculated with the Plant Based Load Evaluation (PBLE) Method 2 transfer function used in the steam dryer design analyses for EPU. The acceptance limits will ensure that the steam dryer stress margins remain above the final minimum alternating stress ratio (MASR) accepted in the EPU design analyses.

3. BFN shall provide a summary of the data and evaluation of predicted and measured pressures, strains, and accelerations at a power level of 3458 MWt. This data will include the BFN-specific bias and uncertainty data and transfer function, revised peak stress table and any revised acceptance limits. The predicted pressures shall include those using both PBLE methods (that is, Method 1 using on-dryer data, and Method 2 using MSL data). It shall be provided to the NRC Project Manager upon completion of the evaluation. TVA shall not increase power above 3458 MWt until the NRC PM notifies TVA that NRC accepts the evaluation or NRC questions regarding the evaluation have been addressed. If no questions are identified within 240 hours after the NRC receives the evaluation, power ascension may continue.

   a. If the on-dryer instrumentation is unavailable and the BFN-specific bias and uncertainty data and transfer function cannot be developed when BFN Unit 3 reaches a power level of 3458 MWt, the BFN Unit 3 power ascension above 3458 MWt will be monitored using the available MSL strain gauges. The predicted dryer loads during the power ascension will be calculated with the PBLE Method 2 transfer function used in the steam dryer design analyses for EPU. The acceptance limits will ensure that the steam dryer stress margins remain above the final MASR accepted in the EPU design analyses.

(b) The following requirements are placed on operation of the facility during the initial power ascension from 3458 MWt to the approved EPU power level of 3952 MWt:

1. At test increments that do not exceed 2.5 percent of 3458 MWt (approximately 86 MWt), TVA shall hold the facility at approximately steady state conditions and collect data from available MSL strain gauges and available on-dryer instrumentation. This data will be evaluated, including the comparison of measured dryer strains to acceptance limits and the comparison of predicted dryer loads based on MSL strain gauge data to acceptance limits. It will also be used to trend and project loads at the next test point and to EPU conditions to demonstrate margin for continued power ascension.

   a. If the on-dryer instrumentation becomes unavailable during power ascension above 3458 MWt, the BFN Unit 3 power ascension above 3458 MWt will be monitored using the available MSL strain gauges. The predicted dryer loads during the power ascension will be calculated with the BFN-specific PBLE Method 2 transfer function developed from the on-dryer instrumentation and MSL strain gauge data taken at the 3458 MWt hold point, the BFN-specific bias and uncertainty data, the revised peak stresses, and revised acceptance criteria developed in item (a)3 above. The acceptance limits will maintain the steam dryer stress margins above a MASR of 1.0.

2. Following the data collection and evaluation at the plateaus at approximately 3,630 MWt, 3,803 MWt, and 3952 MWt, TVA shall provide a summary of the data and the evaluation performed in item (b)1 above to the NRC Project Manager. TVA shall not increase power above these power levels for up to 96 hours after the NRC Project Manager confirms receipt of the summary, unless prior to expiration of the 96 hour period, the NRC Project Manager advises that the NRC staff has no objection to continuation of power ascension.

3. Should the measured strains on the dryer exceed the Level 1 acceptance limits, or alternatively if the dryer instrumentation is not available and the projected load on the dryer from the MSL strain gauge data exceeds the Level 1 acceptance limits, TVA shall return the facility to a power level at which the limits are not exceeded. TVA shall resolve the discrepancy, evaluate and document the continued structural integrity of the steam dryer, and provide that documentation to the NRC Project Manager prior to further increases in reactor power. TVA shall not increase power for up to 96 hours to allow for NRC review and approval of the information.

   a. In the event that acoustic signals (in MSL strain gauge signals) are identified that challenge the dryer acceptance limits during power ascension above 3458 MWt, TVA shall evaluate dryer loads, and stresses, including the effect of ±10 percent frequency shift, and re-establish the acceptance limits and determine whether there is margin for continued power ascension.

b. During power ascension above 3458 MWt, if an engineering evaluation for the steam dryer is required because a Level 1 acceptance limit is exceeded, TVA shall perform the structural analysis using the Steam Dryer Report, Appendix A methods to address frequency uncertainties up to ±10% and assure that peak responses that fall within this uncertainty band are addressed.

4. a. Following the data collection and evaluation at the EPU power level, TVA shall provide a final load definition and stress report of the steam dryer, including the results of a complete re-analysis using the BFN-specific bias and uncertainties and transfer function, to the NRC. The BFN-specific bias and uncertainties summary shall include both PBLE Method 1 and Method 2. This report shall be submitted to the NRC within 90 days of the completion of EPU power ascension testing for BFN Unit 3. Should the results of this stress analysis indicate the allowable stress in any part of the dryer is exceeded, TVA shall reduce power to a level at which the allowable stress is met, evaluate the dryer integrity, and assess any shortcomings in the predictive analysis. The results of this evaluation, including a recommended resolution of any identified issues and a demonstration of dryer integrity at EPU conditions, shall be provided to the NRC for review and approval prior to return to EPU conditions.

   b. Within 30 days after completion of the core flow sweep test at EPU conditions to determine any compounding effect due to alignment of Vane Passing Frequency and Safety Relief Valve resonance frequencies, the TVA shall provide the core flow sweep test results for NRC review.

5. Following the data collection and evaluation at the EPU power level, TVA shall provide a vibration summary report to the NRC. The summary report shall be submitted to the NRC within 90 days of the completion of EPU power ascension testing for BFN Unit 3. The vibration summary report shall include the information in items 5.a through 5.c, as follows:

   a. Vibration data for piping and valve locations deemed prone to vibration and vibration monitoring locations identified in Attachment 45 to the EPU application dated September 21, 2015, including the identified locations associated with MSLs, feedwater lines, safety relief valves and the main steam isolation valves.

   b. An evaluation of the measured vibration data collected in item 5.a above compared against acceptance limits.

   c. Vibration values and associated acceptance limits at approximately 3,630 MWt, 3,803 MWt, and 3952 MWt using the data collected in item 5.a, above.

(c) TVA shall prepare the EPU PAT plan to include the following.

1. Level 1 and Level 2 acceptance limits for on-dryer strain gauges and for projected dryer loads from MSL strain gauge data to be used up to 3952 MWt.

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

3. Activities to be accomplished during 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 TVA application and all supplements to the application in support of the EPU LAR pertaining to the steam dryer before power increase above 3458 MWt.

10. Identify the NRC Project Manager as the NRC point of contact for providing PAT plan information during power ascension.

11. Methodology for updating limit curves.

(d) The following key attributes of the PAT Plan shall not be made less restrictive without prior NRC approval.

1. During initial power ascension testing above 3458 MWt, each of the two hold points shall be at increments of approximately 5 percent of 3458 MWt.

2. Level 1 performance criteria.

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

Changes to other aspects of the PAT Plan may be made in accordance with the guidance of NEI 99-04, "Guidelines for Managing NRC Commitments," issued July 1999.

(e) During the first two scheduled refueling outages after reaching full EPU conditions, TVA shall conduct a visual inspection of all accessible, susceptible locations of the steam dryer in accordance with Boiling Water Reactor Vessels and Internals Project (BWRVIP)-139A (Steam Dryer Inspection and Flaw Evaluation Guidelines) and General Electric (GE) inspection guidelines (SIL 644, BWR Steam Dryer Integrity).

(f) 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 to NRC within 90 days following startup from each of the first two respective refueling outages.

(g) 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 items (e) and (f) provided that a visual inspection of the steam dryer does not reveal any new unacceptable flaw(s) or unacceptable flaw growth that is caused by fatigue, and; (2) upon satisfaction of the requirements specified in item (g).

3.1.4 Neutron Absorber Monitoring Program

In its letter dated July 27, 2016 (Reference 27), the licensee stated that TVA will perform areal density measurements on one Boral sample prior to EPU implementation at Browns Ferry. In addition, TVA accepted the following license condition for the performance of periodic Boral areal density measurement at the EPU:

> The licensee shall, at least once every ten years, withdraw a neutron absorber coupon from the spent fuel pool and perform Boron-10 (B-10) areal density measurement on the coupon. Based on the results of the B-10 areal density measurement, the licensee shall perform any technical evaluations that may be necessary and take appropriate actions using relevant regulatory and licensing processes.

The licensee further stated, in its letter dated July 27, 2016 (Reference 27), that upon issuance of the EPU Amendments, the current Boral Monitoring Program will be modified accordingly to meet the appropriate license condition.

Therefore, the NRC staff is adding license conditions 2.C.(19) for Units 1 and 2, and 2.C.(15) for Unit 3 with the above license condition to the BFN Units 1, 2, and 3 licenses. This license condition is addressed in Section 2.1.8.2 of this SE.

3.1.5 Radiological Consequences Analyses Using Alternative Source Terms

In its letter dated July 29, 2016 (Reference 29), responding to the NRC staff RAI regarding the non-conforming condition and how radiological consequences analyses meet the regulatory requirements, TVA stated that as part of the EPU LAR, it accepts the following license condition for resolution of the ALT pathway non-conforming/degraded condition:

> TVA shall perform facility and licensing basis modifications to resolve the non-conforming/degraded condition associated with the Alternate Leakage Treatment pathway such that the current licensing basis dose calculations (approved in License Amendment Nos. 251/282 (Unit 1), 290/308 (Unit 2) and 249/267 (Unit 3)) would remain valid. These facility and licensing basis modifications shall be complete prior to initial power ascension above 3458 MWt.

Therefore, the NRC staff is adding the above license condition as license conditions 2.C.(20) for BFN Unit 1 and Unit 2, and license condition 2.C.(16) for BFN Unit 3. This license condition is addressed in Section 2.9.1.2 of this SE.

3.2 Changes to Browns Ferry Technical Specifications

The following TS sections, and associated TS Bases, are affected by the proposed EPU for the three BFN Units, except as noted:

- Definitions - Rated Thermal Power (RTP) (TS 1.1)
- Reactor Core Safety Limits (TS 2.1.1)
- Standby Liquid Control (SLC) System (TS 3.1.7)
- Average Planar Linear Heat Generation Rate (APLHGR) (TS 3.2.1)
- Minimum Critical Power Ratio (MCPR) (TS 3.2.2)
- Linear Heat Generation Rate (LHGR) (TS 3.2.3)
- Reactor Protection System (RPS) Instrumentation (TS 3.3.1.1)
- Feedwater and Main Turbine High Water Level Trip Instrumentation (TS 3.3.2.2)
- End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation (TS 3.3.4.1)
- Jet Pumps (TS 3.4.2)
- Containment Atmosphere Dilution (CAD) System (TS 3.6.3.1)
- Residual Heat Removal Service Water (RHRSW) System and Ultimate Heat Sink (UHS) (TS 3.7.1) [BFN Units 2 and 3 only]
- Emergency Equipment Cooling Water (EECW) System and Ultimate Heat Sink (UHS) (TS 3.7.2) [BFN Units 2 and 3 only]
- Main Turbine Bypass System (TS 3.7.5)
- Primary Containment Leakage Rate Testing Program (TS 5.5.12)
- Fuel Storage, Criticality (TS 4.3.1)
- Residual Heat Removal (RHR) Heat Exchanger Performance Monitoring Program (TS 5.5.14)

Sections 3.2.1 through 3.2.16 of this SE provide the NRC staff's review of the changes to the TSs for BFN Units 1, 2, and 3.

3.2.1 Definitions - Rated Thermal Power (RTP) (TS 1.1)

The licensee proposed, in Enclosure 2 of TVA's letter dated October 31, 2016 (Reference 38), to revise the definition of RATED THERMAL POWER (RTP) from the current value of 3458 MWt to 3952 MWt. Revised TS 1.1 states, in part:

RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the (RTP) reactor coolant of 3952 MWt.

This change reflects the proposed approximate 14.3 percent increase in thermal power 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.

3.2.2 Reactor Core Safety Limits (TS 2.1.1)

The current Browns Ferry TS 2.1.1.1 requires that thermal power shall be less than or equal to 25 percent RTP when the reactor steam pressure is less than 585 psig or core flow is less than 10 percent rated core flow. The licensee, in Enclosure 1 of its letter dated October 31, 2016 (Reference 38), proposed to change the less than or equal to 25 percent RTP limit to less than or equal to 23 percent RTP limit. The revision to the RTP limit is based on the fuel thermal limit monitoring threshold. Revised TS 2.1.1.1 states, in part:

> THERMAL POWER shall be ≤ 23% RTP.

The licensee in Section 2.8.2.1.2, "Fuel Thermal Margin Monitoring Threshold," of FUSAR (Reference 164), states:

> 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. For the highest power density reactors at original licensed thermal power (OLTP) conditions, this monitoring threshold was equivalent to bundle powers up to 1.2 MWt. [[

]]

> For EPU, the fuel thermal margin monitoring threshold is scaled down, if necessary, to ensure that monitoring is initiated prior to exceeding an average bundle power of 1.2 MWt. For BFN, the current licensed thermal power (CLTP) of 3458 MWt maintains a bundle power below this threshold at 25% of rated power (0.25*3458 MWt/764 bundles = 1.1 MWt/bundle). However, the threshold must be adjusted to meet this average bundle power criterion for EPU conditions.

100 * (1.2 MWt/bundle * 764 bundles / 3952 MWt) = 23% of EPU RTP

> A change in the fuel thermal monitoring threshold also requires a corresponding change to the Technical Specifications (TS) reactor core safety limit for reduced pressure or low core flow.
>
> The basis for not monitoring thermal limits below this threshold is the large margin to thermal limits as described in the TS Bases. Therefore, with these large margins, there are no transients that have limiting consequences when initiated from the 0 – 23 percent power range.

Since the revised reactor core safety limit is based on the licensee adjusted threshold to meet the average bundle criterion for EPU condition, the NRC staff concludes that the proposed change to TS 2.1.1.1 is bounding for Browns Ferry and is acceptable.

3.2.3 Standby Liquid Control (SLC) System (TS 3.1.7)

SR 3.1.7.5

The licensee proposed, in Enclosure 1 of its letter dated October 31, 2016 (Reference 38), to revise the value of the minimum quantity of Boron-10 (B-10) in the SLC System solution tank from 186 pounds to 203 pounds for BFN Units 2 and 3. The BFN Unit 1 change to the minimum quantity of B-10 (greater than or equal to 203 pounds) in SR 3.1.7.5 was approved by the NRC on March 6, 2007, by Amendment 269, "Five Percent Uprate" (Reference 269).

The licensee provided additional details regarding the requirement for 203 pounds of Boron-10 reflects the change in the required boron concentration in Section 2.8.4.5.1.of PUSAR (Reference 37). The licensee states that SLCS shutdown capability is reevaluated for each fuel reload. The cold boron shutdown concentration of 720 ppm natural boron for Unit 1 does not change for the EPU. The cold boron shutdown concentration of 660 ppm natural boron for Units 2 and 3 changes to 720 ppm for the EPU. No changes are necessary to the solution volume / concentration or to the boron-10 enrichment for the EPU to achieve the required reactor boron concentration for cold shutdown conditions for Unit 1. Because of the increase in the cold boron shutdown concentration for Units 2 and 3, the minimum weight of Boron-10 to be injected to achieve cold shutdown conditions changes for Units 2 and 3 for EPU from 186 pound to 203 pounds. Revised SR 3.1.7.5 states, in part:

> Verify the minimum quantity of Boron-10 in the SLC solution tank and available for injection is ≥ 203 pounds.

The NRC staff in Section 2.8.4.5 of this SE addresses an increase in the cold boron shutdown concentration for BFN Units 2 and 3. The staff states that BFN Unit 1 used a conservative cold shutdown boron concentration value of 720 ppm, while BFN Units 2 and 3 used a more aggressive value of 660 ppm, which needed to be confirmed on cycle-specific basis. Since BFN has increased the B-10 concentration, which significantly reduces the boron injection time, TVA proposed to use the same 720 ppm value for all three units to simplify operator training and engineering design. The NRC staff concludes the proposed change to the SR 3.1.7.5 is acceptable for BFN Units 2 and 3, since it is resulted due to a conservative increase in cold boron shutdowns concentration.

SR 3.1.7.6

The licensee in, Enclosure 1 of its letter dated October 31, 2016 (Reference 38), stated that:

> The SLC system is required to inject borated water solution into the reactor pressure vessel to control reactor power in the event of an ATWS event in accordance with the requirements of 10 CFR 50.62(c)(4). By meeting the conditions specified in SR 3.1.7.6, the SLC System provides a combination of flow capacity and B-10 content equivalent in control capacity to 86 gpm of 13 weight percent natural sodium pentaborate solution.
>
> The proposed change to TS SR 3.1.7.6 provides a more rapid shutdown of the reactor during an ATWS event and considers the increase in heat generated due to EPU. The reduction in the peak suppression pool temperature for EPU is a result of modified plant parameters in the ATWS safety analysis, including an increase in SLC system B-10 enrichment, an increase in the credited SLC storage tank boron concentration, and an increase in the credited SLC flow rate. As a result, the total integrated heat load added to the suppression pool during an ATWS event is reduced, which provides additional NPSH margin for the credited ECCS pumps.
>
> For EPU, the B-10 enrichment is increased to a nominal 94 atom-percent. However, the equation specified in SR 3.1.7.6 can be satisfied by a lower B-10 enrichment by increasing the other variables (i.e., boron concentration and/or pump flow rate). For EPU, the equivalency requirement can be demonstrated if the following relationship is satisfied:
>
> $$\frac{(C)(Q)(E)}{(8.7\text{ wt. }\%)(50\text{ gpm})(94\text{ atom }\%)} \geq 1$$
>
> where,
>
> C = sodium pentaborate solution concentration (wt. %)
> Q = pump flow rate (gpm)
> E = B-10 enrichment (atom % B-10)
>
> If the result of the above equation is numerically greater than or equal to one, the SLC System is capable of shutting down the reactor with significant margin to the acceptance criteria for suppression pool temperature.

The licensee provided additional details for an evaluation of the SLC System for EPU and for the ATWS evaluation under EPU conditions in Sections 2.8.4.5 and Section 2.8.5.7 of PUSAR (Reference 37). Revised SR 3.1.7.6, in part, states:

> Verify the SLC conditions satisfy the following equation:
>
> $$\frac{(\quad C \quad)(\quad Q \quad)(\quad E \quad)}{(8.7\text{ wt. }\%)(50\text{ gpm})(94\text{ atom}\%)} \geq 1$$

The NRC staff evaluated, in Section 2.8.4.5 of this SE, an increase of the B-10 enrichment from 63.1 percent to 94 percent to improve ATWS performance. The NRC staff review shows that this modification increases the SLCS shutdown margin and reduces the integrated heat to containment, which significantly improves ATWS performance. Therefore, the NRC staff concludes that the proposed change to SR 3.1.7.6 is acceptable for Browns Ferry.

3.2.4 Average Planar Linear Heat Generation Rate (APLHGR) (TS 3.2.1)

The licensee, in Enclosure 1 of its letter dated October 31, 2016 (Reference 38), stated that TS 3.2.1 APLHGR Applicability, Required Action B.1, and SR 3.2.1.1 Frequency include requirements associated with a thermal power limit of 25% RTP. The proposed change revises the 25 percent RTP to 23 percent RTP. The revision to the percent RTP is based on the fuel thermal limit monitoring threshold. (Refer to FUSAR Section 2.8.2.1.2.)

Revised TS 3.2.1 states, in part:

APPLICABILITY	THERMAL POWER ≥ 23% RTP.
REQUIRED ACTION B.1	Reduce THERMAL POWER < 23% RTP.

Revised SR 3.2.1.1 states, in part:

FREQUENCY	Once within 12 hours after ≥ 23% RTP

Based on the discussion in SE Section 3.2.2, the NRC staff concludes that the proposed changes to TS 3.2.1 and SR 3.2.1.1 are acceptable.

3.2.5 Minimum Critical Power Ratio (MCPR) (TS 3.2.2)

The licensee in Enclosure 1 of its letter dated October 31, 2016 (Reference 38), stated that TS 3.2.2 MCPR Applicability, Required Action B.1 and SR 3.2.2.1 Frequency, include requirements associated with a thermal power limit of 25 percent. The proposed change revises the 25 percent RTP to 23 percent RTP. The licensee provided additional details regarding the revision to the percent RTP in FUSAR (Reference 164) Section 2.8.2.1.2, based on the fuel thermal limit monitoring threshold

Revised TS 3.2.2 states, in part:

APPLICABILITY	THERMAL POWER ≥ 23% RTP.
REQUIRED ACTION B.1	Reduce THERMAL POWER < 23% RTP.

Revised SR 3.2.2.1 states, in part:

SR 3.2.2.1 FREQUENCY	Once within 12 hours after ≥ 23% RTP

Based on the discussion in SE Section 3.2.2, the NRC staff concludes that the proposed changes to TS 3.2.2 and SR 3.2.2.1 are acceptable.

3.2.6 Linear Heat Generation Rate (LHGR) (TS 3.2.3)

The licensee in Enclosure 1 of its letter dated October 31, 2016 (Reference 38), stated that TS 3.2.3 LHGR Applicability, Required Action B.1 and SR 3.2.3.1 Frequency, include requirements associated with a thermal power limit of 25 percent. The proposed change revises the 25 percent RTP to 23 percent RTP. The revision to the percent RTP is based on the fuel thermal limit monitoring threshold. The licensee provided additional details regarding the revision to the percent RTP in FUSAR (Reference 164) Section 2.8.2.1.2, based on the fuel thermal limit monitoring threshold.

Revised TS 3.2.3 states, in part:

APPLICABILITY:	THERMAL POWER ≥ 23% RTP.
REQUIRED ACTION B.1	Reduce THERMAL POWER < 23% RTP.

Revised SR 3.2.3.1 states, in part:

FREQUENCY	Once within 12 hours after ≥ 23% RTP.

Based on the discussion in SE Section 3.2.2, the NRC staff concludes that the proposed changes to TS 3.2.3 and SR 3.2.3.1 are acceptable.

3.2.7 Reactor Protection System (RPS) Instrumentation (TS 3.3.1.1)

The licensee, in Section 3.1.9, "TS Section 3.3.1.1, RPS Instrumentation," Enclosure 1 of TVA's letter dated October 31, 2016 (Reference 38), proposed the following changes to TS 3.3.1.1:

a. Required Action E.1

The value (in percent RTP) for this limiting condition for operation (LCO) action specifies the power level at which the Turbine Stop Valve – Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure – Low Functions must be armed. The licensee proposes to revise the value for the required action from 30 percent RTP to 26 percent RTP in order to maintain this value at an equivalent absolute value in terms of MWt. Rescaling the percent RTP maintains the same absolute thermal power level that was evaluated and authorized for CLTP.

Revised TS 3.3.1, REQUIRED ACTION E.1 states, in part:

E.1 Reduce THERMAL POWER to < 26% RTP.

Based on the above information, the NRC staff finds this approach affords an equivalent level of protection to the current licensing basis and is acceptable.

b. Surveillance Requirement (SR) 3.3.1.1.2

This SR instructs operators to verify that the absolute difference between APRM readings and calculated power is within specified tolerance. The percent RTP values define the applicability of the SR (i.e., the SR must be performed when the reactor is at or above the specified RTP). The CLTR states that the percent power level above which fuel thermal margin monitoring is

required may change with an EPU. The original plant operating licenses set this monitoring threshold at a typical value of 25 percent of RTP. However, the average bundle power (in MWt) for BFN at 25 percent RTP (pre-EPU) is lower than the average bundle power for BFN at 25 percent EPU RTP.

The licensee proposes to revise the values in the SR from 25 percent RTP to 23 percent RTP. As described in Section 2.8.2.1.2 of the FUSAR (Attachments 8 and 9 of the EPU LAR), the revision to the percent RTP is based on the fuel thermal limit monitoring threshold.

For the EPU, as specified in the CLTR, the fuel thermal margin monitoring threshold is scaled down to ensure that monitoring is initiated by the time the average bundle power reaches the pre-EPU average bundle power (in MWt).

Revised SR 3.3.1.1.2 states, in part:

> ----------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.

Based on the above information and referring to Section 3.2.2 of this SE, the NRC staff finds this change acceptable.

c. Surveillance Requirement (SR) 3.3.1.1.15

This SR pertains to ensuring that certain turbine-related functions are not bypassed when operating above a specified power level. The licensee proposes to revise the value in the SR from the stated analytical limit of 30 percent RTP to 26 percent RTP. Rescaling the percent RTP maintains the same absolute thermal power level that was evaluated and authorized for CLTP.

Revised SR 3.3.1.1.15 states, in part:

> Verify Turbine Stop Valve – Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure – Low Functions are not bypassed when THERMAL POWER is ≥ 26% RTP.

Based on the above information, the NRC staff finds this approach affords an equivalent level of protection to the Browns Ferry current licensing basis and is acceptable.

d. Surveillance Requirement (SR) 3.3.1.1.17

This SR ensures that the oscillation power range monitor will not be inadvertently bypassed in the region of power and flow operation if thermal hydraulic oscillations occur. The licensee proposes to revise the value in the SR from 25 percent RTP to 23 percent RTP. Rescaling of the RTP percent maintains the same absolute thermal power level that was evaluated and authorized for CLTP.

Revised SR 3.3.1.1.17 states, in part:

> Verify OPRM is not bypassed when APRM Simulated Thermal Power is ≥ 23% and recirculation drive flow is < 60% of rated recirculation drive flow.

Based on the above information and referring to Section 3.2.2 of this SE, the NRC staff finds the revised TS is acceptable.

e. Table 3.3.1.1-1, Function 2.a

The ALLOWABLE VALUE in this function is related to the APRM Neutron Flux – High (Setdown) function. The licensee proposes to revise the allowable value for APRM Neutron Flux – High (Setdown) from less than or equal to 15 percent RTP to less than or equal to 13 percent RTP. Rescaling the percent RTP maintains the same absolute thermal power level authorized for CLTP in terms of megawatts thermal.

Revised TS Table 3.3.1.1-1, FUNCTION 2.a states, in part:

> ALLOWABLE VALUE ≤ 13% RTP

Based on the above information and referring to Section 3.2.2 of this SE, the NRC staff finds this approach acceptable.

f. Table 3.3.1.1-1, Function 2.b

The revised ALLOWABLE VALUE for this function is related to the APRM Flow Biased Simulated Thermal Power – High function. The licensee proposes to revise the allowable value for Flow Biased Simulated Thermal Power High for two-loop operation from ≤0.66W + 66% RTP to ≤0.55W + 65.5% RTP. The proposed change also revises Footnote (c) for one-loop operation from [0.66(W - ΔW) + 66.0] % RTP to [0.55 (W - ΔW) + 65.5] % RTP. The new values are based on the proposed changes in power level and were calculated using TVA methodology, "Tennessee Valley Authority Branch Technical Instruction Setpoint Calculations," BTI-EEB-TI-28. This methodology was reviewed and approved by the NRC in a letter dated September 14, 2006 (Reference 158). Additional detail of the staff's review of the calculation and methodology is contained in Section 3.2.1 of this evaluation.

Revised TS Table 3.3.1.1-1, FUNCTION 2. b. states, in part:

> ALLOWABLE VALUE ≤ 0.55 W +65.5% RTP and ≤ 120% RTP[(c)]

Revised TS Table 3.3.1.1-1, footnote (c) states, in part:

> (c) [0.55 W + 65.5% - 0.55 ΔW] RTP when . . .

Based on the above information and referring to Section 3.2.2 of this SE, the NRC staff finds the licensee's approach and the revised TS acceptable.

g. Table 3.3.1.1-1, Function 8

This item addresses the applicable mode for the Turbine Stop Valve – Closure function. The licensee proposes to revise the applicable modes or other specified conditions from 30 percent RTP to 26 percent RTP. Rescaling the percent RTP maintains the same absolute thermal power level that was evaluated and authorized for CLTP.

Regarding above Item g., revised TS Table 3.3.1.1-1, FUNCTION 8 states, in part:

APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS ≥ 26% RTP

Based on the above information and referring to Section 3.2.2 of this SE, the NRC staff finds this approach affords an equivalent level of protection to the Browns Ferry current licensing basis and is acceptable.

h. Table 3.3.1.1-1, Function 9

This item addresses the applicable mode for the Turbine Control Valve Fast Closure, Trip Oil Pressure – Low function. The licensee proposes to revise the applicable modes and other specified conditions from 30 percent RTP to 26 percent RTP. Rescaling the percent RTP maintains the same absolute thermal power level that was evaluated and authorized for CLTP.

Revised TS Table 3.3.1.1-1, FUNCTION 9 states, in part:

APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS ≥ 26% RTP

Based on the above information and referring to Section 3.2.2 of this SE, the NRC staff finds this approach affords an equivalent level of protection to the Browns Ferry current licensing basis and is acceptable.

3.2.8 Feedwater and Main Turbine High Water Level Trip Instrumentation (TS 3.3.2.2)

The licensee stated, in Section 3.1.10 of Enclosure 1 to its letter dated October 31, 2016 (Reference 38), that TS Section 3.3.2.2, Applicability and Required Action C.1, include requirements corresponding to a thermal power limit of 25 percent RTP. The proposed change to LCO 3.3.2.2 will revise the 25 percent RTP to 23 percent RTP. Section 2.8.2.1.2 of the FUSAR (Reference 164) states that the revision to the percent RTP is based on the fuel thermal limit monitoring threshold.

In addition, the CLTR states that the percent power level above which fuel thermal margin monitoring is required may change with an EPU. The original plant operating licenses set this monitoring threshold at a typical value of 25 percent of RTP. However, the average bundle power (in MWt) for BFN at 25 percent RTP is lower than the average bundle power for BFN at 25 percent EPU RTP.

For the EPU, as specified in the CLTR, the fuel thermal margin monitoring threshold is scaled down, to ensure that monitoring is initiated by the time the average bundle power reaches the pre-EPU average bundle power (in MWt).

Revised TS 3.3.2.2, APPLICABILITY states:

THERMAL POWER ≥ 23% RTP.

Revised TS 3.3.2.2, REQUIRED ACTION states:

C.1 Reduce THERMAL POWER to < 23% RTP.

Based on the above information, the NRC staff finds the change to TS 3.3.2.2 acceptable.

3.2.9 End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation (TS 3.3.4.1)

From Section 3.1.11 in Enclosure 1 to TVA letter dated October 31, 2016 (Reference 38), this item addresses the applicability and LCO actions related to the End of Cycle Recirculation Pump Trip Instrumentation. The licensee proposes to revise 30 percent RTP to 26 percent RTP in the following sections of TS 3.3.4.1.

- Applicability.
- Action C.1
- SR 3.3.4.1.2

Rescaling the percent RTP maintains the same absolute thermal power level that was evaluated and authorized for CLTP.

Revised TS 3.3.4.1, APPLICABILITY states:

THERMAL POWER ≥ 26% RTP.

Revised TS 3.3.4.1, REQUIRED ACTION states, in part:

C.1 Reduce THERMAL POWER < 26 percent RTP.

Revised SR 3.3.4.1.2 states, in part:

Verify TSV – Closure and TCV Fast Closure, Trip Oil Pressure – Low Functions are not bypassed when THERMAL POWER is ≥ 26 percent RTP.

Based on the above information, the NRC staff finds the licensee's approach affords an equivalent level of protection to the Browns Ferry current licensing basis and is acceptable.

3.2.10 Jet Pumps (TS 3.4.2)

Note 2 of TS SR 3.4.2.1 states that the surveillance is not required to be performed until 24 hours after operating at over 25 percent RTP. The licensee proposed, in Enclosure 1 of its letter dated October 31, 2016 (Reference 38), to revise the 25 percent RTP in this note to 23 percent RTP. This revision to the percent of RTP is conservative and is consistent with the

other proposed changes from 25 percent RTP to 23 percent RTP that are associated with the fuel thermal limit monitoring threshold. Revised Note 2 of SR 3.4.2.1 states:

> 2. Not required to be performed until 24 hours after > 23% RTP.

Based on the discussion in SE Section 3.2.2, the NRC staff concludes that the proposed change to SR 3.2.4.1 is acceptable.

3.2.11 Containment Atmosphere Dilution (CAD) System (TS 3.6.3.1)

The licensee, in Enclosure 1 of its letter dated October 31, 2016 (Reference 38), stated that:

> Current TS SR 3.6.3.1.1 requires that at least 2500 gallons of liquid nitrogen be stored in each nitrogen storage tank. This volume is being increased to 2615 gallons as a result of the increased production rate of radiolytic gas following a postulated LOCA under EPU conditions. The revised TS value represents the analytical limit assumed in the analysis of the primary containment atmosphere following a postulated LOCA, and does not include allowance for potential nitrogen boil-off and tank level instrumentation inaccuracies. Implementing procedures will include the appropriate margin in tank volume to account for uncertainties. (Refer to FUSAR (Reference 164) Section 2.6.4.).

Revised TS 3.6.3.1, SR 3.6.3.1.1 states, in part:

> Verify ≥ 2615 gal of liquid nitrogen are contained in each nitrogen storage tank.

Based on the discussion in SE Section 2.6.4, "Combustible Gas Control in Containment," the NRC staff concludes that the proposed change to TS 3.6.3.1 is acceptable.

3.2.12 Residual Heat Removal Service Water (RHRSW) System and Ultimate Heat Sink (UHS) (TS 3.7.1) [BFN Units 2 and 3 only]

The licensee, in Enclosure 1 of its letter dated October 31, 2016 (Reference 38), stated that:

> For BFN Units 2 and 3 only, TS 3.7.1 is being revised to remove requirements for the ultimate heat sink (UHS), which are included in TS 3.7.2. Reference to the UHS is being deleted from TS 3.7.1 and the specification title is being changed to "Residual Heat Removal Service Water (RHRSW) System." These changes will make TS 3.7.1 alike for all three BFN units. Specifically:
>
> a. The page headings for TS 3.7.1 are being changed from "RHRSW System and UHS" to "RHRSW System." TS requirements for the UHS are contained in TS 3.7.2.
>
> b. TS LCO 3.7.1 is being revised to remove the requirement for the UHS to be OPERABLE in MODES 1, 2, and 3. This requirement is redundant and already included in TS LCO 3.7.2.
>
> c. TS LCO 3.7.1 ACTION G is being revised to remove the requirement to be in MODE 3 within 12 hours and MODE 4 within 36 hours when the

UHS is inoperable. This requirement is redundant and already included in TS LCO 3.7.2 ACTION B.

d. TS SR 3.7.1.2 and Figure 3.7.1-1 are being deleted because there is no longer a restriction for the UHS average water temperature to be in accordance with the limits specified in Figure 3.7.1-1. When the average water temperature of the UHS is at or below 95 °F, there is no longer a need to make any reduction in rated thermal power for the UHS to be OPERABLE. The provisions of TS SR 3.7.1.2 and Figure 3.7.1-1 are not contained in the BFN Unit 1 TS.

The service water and UHS temperature limit for all three BFN units is specified in TS SR 3.7.2.1 as less than or equal to 95 °F. The EPU design basis analyses for design basis events, including the long term primary containment response after a design basis LOCA, assume a UHS temperature equal to 95 °F. The evaluation supporting this change is described in PUSAR Sections 2.5.3.4 and 2.6.5.1, applies to the UHS service water temperature for all three BFN units, and provides the basis for the revised service water temperature limit used in the safety analyses.

Revised TS 3.7.1 page's header states:

RHRSW Subsystem

The revised TS 3.7.1 deleted "OR" and "UHS inoperable" from TS 3.7.1, CONDITION G.

The revised TS 3.7.1 deleted, in its entirety, SR 3.7.1.2 that is associated with UHS.

The revised TS 3.7.1 deleted, in its entirety, Figure 3.7.1-1 from page 3.7-6 and left the page intentionally blank.

Based on the discussion in SE Sections 2.5.3.4 and 2.6.5.1 of this SE and since the proposed change provides consistency between all three units, the NRC staff concludes that the proposed changes to TS 3.7.1 are acceptable.

3.2.13 Emergency Equipment Cooling Water (EECW) System and Ultimate Heat Sink (UHS) (TS 3.7.2) (BFN Units 2 and 3 only)

The licensee stated, in Enclosure 1 of its letter dated October 31, 2016 (Reference 38), that:

The Note referring to TS SR 3.7.1.2 for additional requirements related to the UHS in the BFN Units 2 and 3 TS is being deleted. This note is being deleted because the UHS requirements in TS 3.7.1 are being deleted (refer to PUSAR Section 2.5.3.4).

The revised TS 3.7.2, deleted, in its entirety, a note from SR 3.7.2.1 that stated "Refer to SR 3.7.1.2 for additional UHS requirements."

Based on the discussion in SE Section 2.5.3.4 of this SE and since the proposed change resulted from an EPU containment analytical model that provides consistency between all three units, the NRC staff concludes that the proposed changes to TS 3.7.2.1 are acceptable.

3.2.14 Main Turbine Bypass System (TS 3.7.5)

The licensee stated, in Enclosure 1 of its letter dated October 31, 2016 (Reference 38), that:

> TS 3.7.5 Applicability and Required Action B.1 include requirements corresponding to thermal power limits of 25% RTP. The proposed change revises the 25% RTP to 23% RTP. The revision to the % RTP is conservative, providing consistency with the other proposed changes from 25% RTP to 23% RTP that are associated with the fuel thermal limit monitoring threshold. (Refer to FUSAR (Reference 164) Section 2.8.2.1.2.)

Revised TS 3.7.5, APPLICABILITY states:

> THERMAL POWER ≥ 23% RTP.

Revised TS 3.7.5, REQUIRED ACTION states, in part:

> C.1 Reduce THERMAL POWER to < 23% RTP.

Based on the discussion in SE Section 3.2.2, the NRC staff concludes that the proposed changes to TS 3.7.5 are acceptable.

3.2.15 Fuel Storage, Criticality (TS 4.3.1)

The licensee in Enclosure 1 of its letter dated October 31, 2016 (Reference 38), stated that:

> TS 4.3.1.1 includes spent fuel storage rack requirements for k-effective (current TS 4.3.1.1 a) and fuel assembly spacing (current TS 4.3.1.1 b). The proposed change adds a new TS 4.3.1.1 b to provide control of the maximum reactivity of fuel assemblies stored in the Spent Fuel Pool (SFP). TS 4.3.1.1 b. Fuel assemblies having a maximum k-infinity of 0.8825 in the normal spent fuel pool storage rack configuration; and the proposed limit is consistent with the BFN SFP Criticality Safety Analysis (CSA) documented in ANP-3160(P), Browns Ferry Nuclear Plant Units 1, 2, and 3 Spent Fuel Storage Pool Criticality Safety Analysis for ATRIUM 10XM Fuel, Revision 1. The proposed TS establishes an acceptance criterion that is based on the maximum fuel assembly reactivity result from the CSA. Therefore, the proposed change ensures that the safety margin established in the analysis is maintained. As a result of the addition of new TS 4.3.1.1 b, an administrative change is proposed to renumber the current TS requirement associated with fuel assembly spacing from TS 4.3.1.1 b to TS 4.3.1.1 c.

Revised TS 4.3.1.1 states:

4.3 Fuel Storage

4.3.1 Criticality

4.3.1.1 The spent fuel storage racks are designed and shall be maintained with:

a. keff ≤ 0.95 if fully flooded with unborated water, which includes an allowance for uncertainties as described in Section 10.3 of the FSAR; and

b. Fuel assemblies having a maximum k-infinity of 0.8825 in the normal spent fuel pool storage rack configuration; and

c. A nominal 6.563 inch center to center distance between fuel assemblies placed in the storage racks.

Based on the discussion in SE Section 2.8.6, the NRC staff concludes that the proposed changes to TS 4.3.1 are acceptable.

3.2.16 Primary Containment Leakage Rate Testing Program (TS 5.5.12)

The licensee in Enclosure 1 of its letter dated October 31, 2016 (Reference 38), stated that:

The peak calculated containment internal pressure for the design basis accident (DBA) loss of coolant accident (P_a) is being revised from 50.6 psig to 49.1 psig for BFN Units 2 and 3. For BFN Unit 1, the peak calculated containment internal pressure for the DBA loss of coolant accident (P_a) is being revised from 48.5 psig to 49.1 psig. The revised event initial conditions for EPU, the selection of M&E inputs for Units 2 and 3 to be consistent with the current licensing basis for Unit 1, and uniform modeling in the containment analysis for all three BFN units account for these changes. The same analytical inputs and assumptions are now used in the containment analysis for all three BFN units (refer to PUSAR Sections 2.2.4.1 and 2.6.3.1 and Table 2.6-1).

Revised TS 5.5.12 states, in part:

> The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is 49.1 psig. The maximum allowable primary containment leakage rate, La, shall be 2% of primary containment air weight per day at P_a.

The licensee in Note 13 of Table 2.6.1, "Browns Ferry Containment Performance Results," in Enclosure 1 in (Reference 38) stated, in part, that:

> The reduction in peak pressure for Browns Ferry Units 2 and 3 is due to the selection of bounding mass and energy release data points for input into the GEH M3CPT code that more closely match the GEH LAMB code break flow output as compared to the selection used for the Browns Ferry Unit 2 and 3 analysis for power uprate supporting CLTP (Reference 84). This technique,

which is consistent with the current analysis used for Unit 1, results in lower mass and energy release to the drywell, which produces a lower peak drywell pressure and temperature at the same power level.

Based on the discussion in SE Section 2.6.3.1 of this SE and since the proposed change provides consistency between all three units, the NRC staff concludes that the proposed changes to TS 5.5.12 are acceptable.

3.2.17 Residual Heat Removal (RHR) Heat Exchanger Performance Monitoring Program (TS 5.5.14)

The licensee in Enclosure 1 of its letter dated October 31, 2016 (Reference 38), stated that:

> License Conditions 2.C.(13), 2.C.(14), and 2.C.(7), Transition License Condition 3, for Browns Ferry Nuclear Plant (BFN) Units 1, 2, and 3, respectively, incorporate by reference Table S-3 implementation Item 49 of TVA letter CNL-15-224, dated October 20, 2015. Table S-3 implementation Item 49 states:
>
> > Revise the program that monitors BFN Residual Heat Removal (RHR) heat exchanger performance for consistency with the assumptions of the NFPA [National Fire Protection Association] 805 Net Positive Suction Head (NPSH) analysis. The monitoring program shall include verification that the tested worst fouling resistance, with measurement uncertainty added, of all BFN Units 1, 2, and 3 RHR heat exchangers is less than the design value of 0.001517 hr-ft2-F/BTU and the worst tube plugging is less than 4.57 percent.
>
> The NFPA 805 license condition associated with implementation item 49 is proposed to be deleted. The RHR Heat Exchanger Performance Monitoring Program has already been established as required by the NFPA 805 license condition. These NFPA 805 license condition requirements have been incorporated into the applicable implementing procedures. In order to support deletion of the NFPA 805 license condition associated with implementation item 49, it is proposed to add RHR Heat Exchanger Performance Monitoring Program requirements to the Administrative Controls section of the BFN Technical Specifications (TS). Specifically, a new TS 5.5.14, "Residual Heat Removal (RHR) Heat Exchanger Performance Monitoring Program," is proposed to be added. The TS requires the establishment of a program to ensure the RHR heat exchangers are maintained in a condition that meets or exceeds the minimum performance capability assumed in the EPU containment analyses, which support not taking credit for containment accident pressure in the NPSH analyses. The TS requires RHR heat exchanger performance testing and overall uncertainty in the fouling resistance to be performed in accordance with the guidelines in the EPRI report, EPRI 3002005340, "Service Water Heat Exchanger Guidelines," dated May 2015. The TS requires the program to include the following.
>
> a. Provisions for periodically monitoring RHR heat exchanger performance, including frequency of monitoring and methodology for considering uncertainty of the result.

b. Acceptance criteria for RHR heat exchanger worst fouling resistance and number of plugged tubes.

c. Limitations and compensatory actions if degraded performance is observed.

d. Controls for changes to program requirements.

The TS requires the details of the program to be described in the Updated Final Safety Analysis Report (UFSAR). Placing the RHR Heat Exchanger Performance Monitoring Program in the BFN TS, with details of the program included in the UFSAR, provides assurance BFN RHR heat exchanger performance will be maintained consistent with BFN analysis and licensing bases. Changes to the BFN analysis and licensing bases associated with the RHR Heat Exchanger Performance Monitoring Program details included in the UFSAR will be controlled in accordance with 10 CFR 50.59, "Changes, tests, and experiments." Including the fouling resistance and tube plugging acceptance criteria in the UFSAR enables BFN to address the impact of potential heat exchanger degraded conditions, associated fouling resistance or tube plugging, on past operability/functionality within the TVA Corrective Action Program. The current NFPA 805 license condition, with explicit limits, does not facilitate this type of past thermal performance evaluation.

Added TS 5.5.14 states:

5.5.14 <u>Residual Heat Removal (RHR) Heat Exchanger Performance Monitoring Program</u>

This program is established to ensure that the RHR heat exchangers are maintained in a condition that meets or exceeds the minimum performance capability assumed in containment analyses, which support not taking credit for containment accident pressure in the NPSH analyses. The RHR heat exchanger testing and determination of overall uncertainty in the fouling resistance shall be in accordance with the guidelines in EPRI report, EPRI 3002005340, Service Water Heat Exchanger Test Guidelines, May 2015. This program establishes the following attributes.

a. The program establishes provisions to periodically monitor RHR heat exchanger thermal performance. The program includes frequency of monitoring and the methodology considers uncertainty of the result.

b. The program establishes and controls acceptance criteria for RHR heat exchanger worst fouling resistance and number of plugged tubes.

c. The program establishes limitations and allows for compensatory actions if degraded performance is observed.

d. Changes to the program shall be made under appropriate administrative review.

e. Details of the program including program limitations, compensatory actions for degraded performance, testing method, data acquisition method, data reduction method, overall uncertainty determination method, thermal performance analysis, acceptance criteria, and computer programs used that meet the 10 CFR 50 Appendix B and 10 CFR 21 requirements are described in the UFSAR.

Based on the above information and referring to Section 2.6.5.3, "Elimination of CAP Credit in NPSH Analyses," of this SE, the NRC staff finds revised TS is acceptable.

4.0 REGULATORY COMMITMENTS

The licensee has made no regulatory commitments in its application for the EPU. The licensee stated in its Attachment 1 of the LAR (Reference 1) that those actions associated with the amendment approval will be complete prior to implementation of the EPU, except where those actions require an increase in power above the currently licensed power level. In those instances, defined actions are incorporated into license conditions and will be completed during power ascension.

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 has identified 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. These do not constitute inspection requirements, but are intended to give inspectors insight into important bases for approving the EPU.

The following is a list of activities/inspections that are being evaluated and finalized, by the NRC staff in Region II, to be performed during and after implementation of the EPU:

- Safety Evaluations (10 CFR 50.59) – The region has previously completed one sample and has plans to review two additional 10 CFR 50.59 evaluations to evaluate impact on safety analysis margins.

- Plant Modifications – The region has previously completed two samples and has plans to review two additional plant modifications to evaluate the impact of those changes on primary systems within the cornerstones.

- Post-Modification/Surveillance Testing – The region will review multiple post-modification and surveillance tests to evaluate impact on core cooling, containment cooling, and high ECCS flow rates.

- Major Integrated Testing – The region will review the NRC SER when issued and select major tests to be monitored, including at least one large transient and/or integrated system performance test.

- Integrated Plant Operations – The region will review the EPU Power Ascension Test Plan and witness the initial power ascension including focus on operator actions and review of vibration data.

- Flow Accelerated Corrosion and Erosion Program Reviews – The region will implement IP 49001 to review the licensee's Erosion and Flow Accelerated Corrosion programs.

- Regulatory Commitments/Recommended Areas for Inspection – The region will review the NRC SER when issued and verify licensee has taken the required actions.

- Problem Identification and Resolution – The region will verify the licensee is identifying problems related to power uprate, at an appropriate threshold, and is entering them into the corrective action program.

In addition to the areas for inspection identified above, NRC Inspection Procedure 71004, "Power Uprate," dated April 30, 2010 (Reference 270), provides guidance for conducting inspections associated with power uprate amendments including considerations for selecting samples.

6.0 PUBLIC COMMENTS

On July, 5 2016, the NRC staff published in the *Federal Register* a "Notice of Consideration of Issuance of Amendments to Facility Operating Licenses, Proposed No Significant Hazards Consideration Determination, and Opportunity for a Hearing," associated with the proposed amendment request (81 FR 43666). In accordance with the requirements in 10 CFR 50.91, "Notice for public comment; State consultation," the notice provided a 30-day period for public comment on the proposed NSHC determination. A public comment was received on August 3, 2016 (Reference 271) regarding the proposed amendment (Reference 1). The public comment states, in part, that:

> BEST/MATRR alleges that non-conservative computer safety model analyses were performed in order to justify the EPU for BFN. As explained in these comments, experimental data indicates that the EPU analyses under-predict the rates of the chemical reaction between zirconium and steam that would occur in the event of a loss-of-coolant accident ("LOCA"). This means that the analyses under-predict the rates in which energy (heat) is released, hydrogen generated, and zirconium fuel-cladding oxidized by the zirconium-steam reaction.
>
> On November 17, 2009, Commenter submitted a 10 C.F.R. § 2.802 petition for rulemaking, PRM-50-93, which addresses issues similar to those raised by BEST/MATRR in these comments. However, the NRC is still reviewing PRM-50-93, more than six years after it was submitted. It is difficult to know how long the NRC will continue reviewing PRM-50-93. But there is ample evidence that the Browns Ferry EPU analyses under-predict the zirconium-steam reaction rates that would occur in the event of a LOCA.

Further, the public comment addressed the AREVA LOCA analyses that were conducted to help justify the amendment request for the EPU for BFN. As indicated by the public comment:

> AREVA's LOCA analyses regarding the EPU for BFN are discussed in three AREVA reports: ANP-3377NP (regarding ATRIUM 10XM fuel), ANP-3378NP (regarding ATRIUM 10XM fuel), and ANP-3384NP (regarding ATRIUM-10 fuel). An important result of a LOCA analysis is the value that the maximum temperature the cladding of the fuel rods is predicted to reach: the peak cladding temperature ("PCT"). The LOCA analyses regarding the EPU for BFN discussed in ANP-3377NP, ANP-3378NP, and ANP-3384NP, predicted PCTs of 2030 °F, 2008 °F, and 2086 °F, respectively.
>
> So the overall predicted PCT is 2,030 °F for ATRIUM 10XM fuel, which is used at BFN (Units 1, 2, and 3). AREVA's analyses "were performed for a [reactor] core composed entirely of ATRIUM 10XM fuel at beginning-of-life (BOL) conditions. Calculations assumed an initial core power of 102% of 3952 MWt, providing an analysis licensing basis power of 4031 MWt. The 2.0% increase reflects the maximum uncertainty in monitoring reactor power, as per NRC requirements. 3952 MWt corresponds to 120% of the original licensed thermal power (OLTP) and is referred to as extended power uprate (EPU)."
>
> And the overall predicted PCT is 2,086 °F for ATRIUM-10 fuel, which is used at BFN (Units 1, 2, and 3). Apparently, the plan for BFN is that all three reactors will primarily use ATRIUM 10XM fuel after the EPU is implemented. The plan is to maybe include some ATRIUM-10 fuel "in a transition cycle" along with ATRIUM 10XM fuel after the EPU is implemented. "At EPU power, any ATRIUM-10 fuel would be in its third cycle of operation.

Regarding the computer safety model that AREVA used to conduct LOCA analyses for the amendment request for the EPU for BFN, the public comment states, in part, that:

> AREVA has stated that "[t]he models and computer codes used by AREVA for LOCA analyses [regarding the EPU for BFN] are collectively referred to as the EXEM BWR-2000 Evaluation Model." The EXEM BWR-2000 Evaluation Model has been approved for reactor licensing analyses by the NRC.
>
> The EXEM BWR-2000 Evaluation Model LOCA calculations for the EPU for BFN "were performed in conformance with 10 CFR 50 Appendix K requirements and satisfy the event acceptance criteria identified in 10 CFR 50.46." In regard to the zirconium-steam reaction that would occur in the event of a LOCA, 10 CFR 50 Appendix K, I.A.5 requires that "[t]he rate of energy release, hydrogen generation, and cladding oxidation from the metal-water reaction shall be calculated using the Baker-Just [correlation]."

The public comment also alleged, in part, that:

> ...non-conservative computer safety model analyses were performed in order to justify the EPU for BFN.

> ...experimental data indicates that the EPU analyses under-predict the rates of the chemical reaction between zirconium and steam that would occur in the event of a loss-of-coolant accident (LOCA). This means that the analyses under-predict the rates in which energy (heat) is released, hydrogen generated, and zirconium fuel-cladding oxidized by the zirconium-steam reaction.

The public comment was mainly concentrated on experimental data and the analyses associated with the calculation of peak cladding temperature (PCT) that were used in development of the Baker-Just correlation. The public comment also referred to the petitions for rulemaking (PRMs) associated with 10 CFR 50.46 and 10 CFR Part 50, Appendix K.

Specifically as part of the LAR, TVA submitted reports showing that Browns Ferry would continue to meet the PCT limits using calculations consistent with Appendix K requirements. However, the public comment does not state that TVA performed such calculations using the Baker-Just equation inappropriately or they are not consistent with Appendix K. Rather, the public comment discusses the adequacy of the Baker-Just equation itself. The public comment states that TVA's modeling in the loss of coolant accident analysis is "scientifically indefensible" because the Baker-Just calculation required by the NRC's regulations underpredicts the rate of heat generation, hydrogen generation, and zirconium fuel-cladding oxidation during a loss of coolant accident, and that TVA did not "scientifically demonstrate" that the peak cladding temperature will not exceed regulatory limits during a LOCA after the EPU. The public comment concluded that the amendment request for the EPU for Browns Ferry should be denied, because non-conservative computer safety model analyses were performed in order to justify the EPU for Browns Ferry.

The licensee's use of Baker-just calculation is required by the NRC regulations. The comment did not provide any reason to believe there was improper use of that equation by TVA. The challenge to the NRC regulation continues related to this comment to be reviewed on a generic basis in connection with the PRM.

In summary, the public comment did not claim that the EPU modeling was not performed in accordance with regulatory requirements, or point to any other error in TVA's application. Rather, the basis for the public comment is that TVA's modeling applied an inadequate and non-conservative NRC regulatory requirement (that is, use of the Baker-Just equation), not that NRC regulations were evaded or misapplied.

Based on the above discussions, the NRC staff determined that the issues discussed in the public comment do not specifically pertain to the inadequacy of the LOCA analysis performed by TVA associated with Browns Ferry EPU. Therefore, the staff concluded that there is reasonable assurance that the health and safety of the public will continue to be protected following implementation of the EPU.

7.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Alabama State official was notified on June 19, 2017, of the proposed issuance of the amendment. The State official did not have any comments.

8.0 ENVIRONMENTAL CONSIDERATION

Pursuant to 10 CFR 51.21, 51.32, 51.33, and 51.35, a draft Environmental Assessment (EA) and finding of no significant impact (FONSI) was published in the *Federal Register* (FR) on December 1, 2016 (81 FR 86732). The draft EA provided a 30-day opportunity for public comment. No comments were received on the draft EA and FONSI.

By letter dated January 20, 2017 (Reference 39), the licensee described changes to the proposed transmission system upgrades necessary to ensure transmission system stability at EPU power levels. As a result, the licensee, in its letter dated February 3, 2017 (Reference 40), provided the NRC staff markups to the published draft revised EA and FONSI. Although the attached EA and FONSI include the revised information, the NRC has determined to issue the revised EA and FONSI as final, rather than as revised draft, for the following reasons, as documented in the NRC's letter dated May 22, 2017 (Reference 272):

- NRC regulations do not require the issuance of a draft EA; only the option of issuing a draft FONSI.

- The additional changes to the transmission system upgrades would not result in any significant environmental impacts to any environmental resources.

- Endangered Species Act (ESA) consultations between NRC and the U.S. Fish and Wildlife Service (FWS) would not be required because there would be no effects to listed species or critical habitats as a result of the proposed EPU. TVA has also determined that no species occur in areas that would be affected by any of the transmission system upgrades or that would otherwise require ESA consultation between TVA and FWS.

- TVA will be required to obtain permits and approvals prior to implementing the system upgrades, which will further bound any environmental impacts. While the NRC must consider transmission system upgrades in its National Environmental Policy Act (NEPA) review as reasonably foreseeable connected actions, such upgrades are not within NRC's regulatory authority.

- TVA, as a federal entity, is required to conduct its own separate environmental review of any transmission system upgrades and routing studies, as necessary, in accordance with NEPA. Similarly, TVA would be required to conduct ESA consultation with the FWS if any currently unforeseen effects on listed species are identified prior to TVA undertaking the transmission system upgrades.

- The NRC draft EA and FONSI are not significantly affected by the transmission system upgrades. The new information in the final EA does not change the underlying conclusions of the EA for any resource, and also does not change the FONSI.

- The NRC received no public comments on the draft EA and FONSI.

The final EA was published in the *Federal Register* on May 31, 2017 (82 FR 24998). 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.

Subsequently, the licensee in its letter dated June 12, 2017 (Reference 42), informed the NRC of three editorial errors in the published EA. The licensee, in an enclosure to its letter, provided the corrected markups to the EA and FONSI. The NRC staff reviewed the marked up pages and finds that the published EA and FONSI are not affected by the identified editorial corrections.

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 TVA letter to NRC dated September 21, 2015, "Proposed Technical Specifications Change TS-505 – Request for License Amendments – Extended Power Uprate," (Agencywide Documents Access and Management System (ADAMS) Accession No. ML15282A152).

2 TVA letter to NRC dated November 13, 2015, "Proposed Technical Specifications Change TS-505 - Request for License Amendments - Extended Power Uprate - Supplemental Information," (ADAMS Accession No. ML15317A361).

3 TVA letter to NRC dated December 15, 2015, "Proposed Technical Specifications (TS) Change TS-505 – Request for License Amendments - Extended Power Uprate (EPU) - Supplement 1, Spent Fuel Pool Criticality Safety Analysis Information," (ADAMS Accession No. ML15351A097).

4 TVA letter to NRC dated December 15, 2015, "Proposed Technical Specifications Change TS-505 – Request for License Amendments – Extended Power Uprate - Supplement 2 MICROBURN-B2 Information," (ADAMS Accession No. ML15351A113).

5 TVA letter to NRC dated December 18, 2015, "Proposed Technical Specifications (TS) Change TS-505 - Request for License Amendments - Extended Power Uprate (EPU) - Supplement 3, Interconnection System Impact Study Information," (ADAMS Accession No. ML15355A413).

6 TVA letter to NRC dated February 16, 2016, "Proposed Technical Specifications (TS) Change TS-505 - Request for License Amendments - Extended Power Uprate (EPU) - Supplement 4, Responses to Requests for Additional Information," (ADAMS Accession No. ML16049A248).

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Attachment:
List of Acronyms

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LIST OF ACRONYMS

1/4T	one-quarter of the reactor pressure vessel wall thickness
2RPT	two recirculation pump trip
AAC	alternate AC source
AC	alternating current
ADAMS	Agencywide Document Access Management System
ADS	depressurization system
AEC	Atomic Energy Commission
AL	analytical limit
ALARA	as low as reasonably achievable
AMP	Aging Management Program
ANS	American Nuclear Society
ANSI	American National Standards Institute
AOO	anticipated operational occurrence
APLHGR	average planar linear heat generation rate
APRM	average power range monitor
ARAVS	auxiliary and radwaste area ventilation system
ARI	alternate rod insertion
ART	adjusted reference temperature
ASDC	alternate shutdown cooling
ASME	American Society of Mechanical Engineers
ASR	alternating stress ratio
AST	alternative source term
ASTM	American Society for Testing and Materials
ATWS	anticipated transient without scram
ATWSI	anticipated transient without scram with instabilities
AV	allowable value
AVS	acoustic vibration suppressors
B-10	Boron-10
BFN	Browns Ferry Nuclear Plant
B&PV	boiler and pressure vessel
B&Us	bias and uncertainties
BL	bulletin
BLEU	blended low enrichment uranium
BOP	balance-of-plant
BSP	backup stability protection
BTP	Branch Technical Position

BTU	British thermal unit
BUF	bump-up factor
BWR	boiling-water reactor
BWROG	BWR Owners Group
BWRVIP	Boiling Water Reactor Vessel and Internals Project
CAD	containment atmosphere dilution
CAP	containment accident pressure
CBP	condensate booster pump
CDF	core damage frequency
cfm	cubic feet per minute
CFR	*Code of Federal Regulations*
CFS	condensate and feedwater system
CGU	commercial grade uranium
CLTP	current licensed thermal power
CLTR	Uprate Licensing Topical Report
CO	condensation oscillation
CP	condensate pump
CPPU	constant pressure power uprate
CPR	critical power ratio
CRAVS	control room area ventilation system
CRD	control rod drive
CRDA	control rod drop accident
CRDM	control rod drive mechanism
CRDS	control rod drive system
CRHZ	control room habitability zone
CS	core spray
CSST	common station service transformer
CST	condensate storage tank
CTT	cooling tower transformer
CUF	cumulative usage factor
CWS	circulating water system
DAS	data acquisition system
DBA	design basis accident
DBE	design basis event
DBLOCA	design basis loss-of-coolant accident
DC	direct current
DCD	design certification document
DG	draft guide

DHR	decay heat removal
DIVOM	delta-over-initial-oscillation magnitude
DOF	degrees-of-freedom
DOR	Division of Operating Reactors
DSS	Division of Safety System
DV	degraded voltage
DW	dead weight
EA	Environmental Assessment
EAB	exclusion area boundary
ECCS	emergency core cooling system
EDG	emergency diesel generator
EECW	emergency equipment cooling water
EFDS	equipment and floor drainage system
EFPY	effective full power years
EHPM	emergency high pressure make-up
EHC	Electro-Hydraulic Control
ELTR1	Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate
ELTR2	Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate
EMA	equivalent margin analysis
EOC	cycle end of cycle
EOI	emergency operating instruction
EOLE	end-of-license-extension
EOP	emergency operating procedure
EPG	emergency procedure guideline
EPRI	Electric Power Research Institute
EPU	extended power uprate
EQ	environmental qualification
ESA	Endangered Species Act
ESF	engineered safety feature
ESBWR	economic simplified boiling water reactor
ESFAS	engineered safety feature actuation system
ESFVS	engineered safety feature ventilation system
°F	degree Fahrenheit
FAC	flow-accelerated corrosion
F&Os	facts and observations
FEA	Finite Element Analysis
FEM	finite-element model

FHA	fuel handling accident
FIV	flow-induced vibration
FONSI	Finding of no Significant Impact
FPCCS	fuel pool cooling and cleanup system
FPP	fire protection program
FPS	fire protection system
FPRA	fire probabilistic risk assessment
FRF	frequency response function
FSAR	final safety analysis report
FSS	Fire Safe Shutdown
ft/s	feet per second
ft^2	square feet
ft^3	cubic feet
FUSAR	Fuel Uprate Safety Analysis Report
FWCF	Feedwater controller failure
FWS	Fish and Wildlife Service
GALL	Generic Aging Lessons Learned
GDC	general design criterion/criteria
GE	General Electric
GEH	GE-Hitachi Nuclear Energy Americas LLC
GGNS	Grand Gulf Nuclear Station
GL	generic letter
gpm	gallons per minute
GWMS	gaseous waste management system
HCOM	hot channel oscillation magnitude
HELB	high energy line break
HEP	human error probability
HEPA	high-efficiency particulate air
HF	high frequency
HFEs	human failure events
HP	horsepower
HPCI	high pressure coolant injection
HSI	human-system interface
HRA	human reliability analysis
HVAC	ventilation and air conditioning
HWC	Hydrogen Water Chemistry
Hz	hertz
IASCC	irradiation-assisted stress-corrosion cracking

IBA	intermediate break accident
I&C	instrumentation and controls
ICF	increased core flow
IEEE	Institute of Electrical and Electronics Engineers
IEPRA	internal events PRA
IGSCC	intergranular stress-corrosion cracking
IN	information notice
IPB	isolated phase bus
IPE	individual plant examination
IPEEE	individual plant examination of external events
IORV	inadvertent opening of a relief valve
ISG	interim staff guidance
ISP	integrated surveillance program
IST	inservice testing
K_{eff}	multiplication factor
kV	kilovolt
LAR	license amendment request
lbm/hr	pound mass per hour
LERF	large early release frequency
LF	low frequency
LFWH	Loss of feedwater heater
LHGR	linear heat generation rate
LLHS	light load handling system
LOCA	loss-of-coolant accident
LOFW	limiting loss of feedwater
LOOP	loss of offsite power
LPCI	low pressure coolant injection
LPCS	low pressure core spray
LPZ	low population zone
LRNB	Load rejection no bypass
LTP	lower tie plate
LWMS	liquid waste management system
MAAP	modular accident analysis program
MASR	minimum alternating stress ratio
MAPLHGR	maximum average planar linear heat generation rate
MC	main condenser
MCES	main condenser evacuation system
MCPR	minimum critical power ratio

M&E	mass and energy
MELB	moderate-energy line break
MELLLA	maximum extended load line limit analysis
Mlbm/hr	million pound mass per hour
MOV	motor-operated valve
MPT	main power transformer
MS	main steam
MSIV	main steam isolation valve
MSIVC	main steam isolation valve closure
MSIVLCS	main steam isolation valve leakage control system
MSL	main steam line
MSLB	main steam line break
MSLBA	main steam line break accident
MSRV	main steam relief valve
MSSS	main steam supply system
MST	main steam tunnel
MVA	megavolts amperes
MVAR	megavolts amperes reactive
MW	megawatt
MWe	MW electric
MWt	megawatt thermal
NCS	nuclear criticality safety
NDE	nondestructive examination
NEI	Nuclear Energy Institute
NEPA	National Environmental Policy Act
NFPA	National Fire Protection Association
NMCA	Nobel Metal Chemical Application
NPSH	net positive suction head
NPSHa	NPSH available
NPSHr	NPSH required
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NSSS	nuclear steam supply system
OER	Operating Experience Review
OLMCPR	operating limit minimum critical power ratio
OLTP	original licensed thermal power
OM	operation and maintenance
OPRM	oscillation power range monitor

PAT	power ascension test
PATP	power ascension test plan
PBLE	plant based load evaluation
PCT	peak cladding temperature
PM	preventive maintenance
ppb	parts per billion
ppm	parts per million
PRA	probabilistic risk assessment
PRFO	pressure regulator failure-open
PSD	power spectral density
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PTC	Performance Test Codes
P-T	pressure-temperature
PUAR	plant unique analysis report
PUSAR	Power Uprate Safety Analysis Report
PWR	pressurized-water reactor
PWSCC	primary water stress-corrosion cracking
RAI	request for additional information
RBCCW	reactor building closed cooling water
RBM	rod block monitor
RCIC	reactor core isolation cooling
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
RCW	raw cooling water
RDLB	recirculation-pump discharge line break
RDSs	replacement steam dryer
REBOL	reactivity equivalent beginning-of-life
RFO	refueling outage
RG	Regulatory Guide
RFWT	reduced feedwater temperature
RHR	residual heat removal
RHRSW	residual heat removal service water
RIPD	reactor internal pressure difference
RMS	root mean square
RPT	recirculation pump trip
RPS	reactor protection system
RPV	reactor pressure vessel

RRP	reactor recirculation pump
RS	Review Standard
RSD	replacement steam dryer
RSLB	recirculation suction line break
RTP	rated thermal power
RVI	reactor vessel internal
RWCU	reactor water cleanup
RWM	rod worth minimizer
SAF	single active failure
SAFDL	specified acceptable fuel design limit
SAG	severe accident guideline
SAMG	Severe Accident Mitigation Guideline
SAR	Safety Analysis Report
SBA	small break accident
SBO	station blackout
SC	safety communication
SDC	shutdown cooling
SE	safety evaluation
SER	Safety Evaluation Report
SFA	Steam/Feedwater Application
SFP	spent fuel pool
SFPAVS	spent fuel pool area ventilation system
SGT	standby gas treatment
SGTS	standby gas treatment system
SIL	Service Information Letter
SIS	system impact study
SJAE	steam jet air ejector
SLB	steam line break
SLC	standby liquid control
SLCS	standby liquid control system
SLO	single loop operation
SMT	scale model test
SORV	stuck open relief valve
SP	suppression pool
SPC	suppression pool cooling
SPCB	Siemens Power Corporation B
SR	surveillance requirement
SRM	Staff Requirements Memorandum

SRP	Standard Review Plan
SRV	safety relief valve
SSC	structures, systems, and component
SSE	safe-shutdown earthquake
SSW	sacrificial shield wall
SSLB	small steam line break
SVC	static VAR compensator
SWMS	solid waste management system
SWS	service water system
TAVS	turbine area ventilation system
TBS	turbine bypass system
TCV	turbine control valve
TEDE	total effective dose equivalent
TFSP	turbine first-stage pressure
TID	total integrated doses
TR	topical report
TS	technical specification
TSS	transmission system study
TSV	turbine stop valve
TTNB	Turbine trip no bypass
TVA	Tennessee Valley Authority
UFSAR	Updated Final Safety Analysis Report
UHS	ultimate heat sink
USE	upper-shelf energy
USST	unit station service transformer
VPF	vane passing frequencies

SUBJECT: BROWNS FERRY NUCLEAR PLANT, UNITS 1, 2, AND 3 - ISSUANCE OF AMENDMENTS REGARDING EXTENDED POWER UPRATE (CAC NOS. MF6741, MF6742, AND MF6743) DATED AUGUST 14, 2017

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OFFICE	DORL/ LPL2-2/PM	DORL/ LPL2-2/LA	DRA/AFPB/ BC	DRA/APLA/ BC	DRA/APHB/ BC	DRA/ARCB/ BC (DA)	DE/EEEB/ BC
NAME	FSaba	BClayton	GCasto	SRosenberg	SWeerakkody	UShoop	JZimmerman
DATE			06/16/16**	09/07/16**	07/29/16**	08/14/16**	10/04/16** 02/16/17 (Revised)*
OFFICE	DE/EVIB/ BC	DE/EICB/ BC	DE/EPNB/ BC (Section 2.1.4)	DE/EMCB/ BC(A) (Non-RSD)	DE/ESGB/ BC(A)	DSS/SRXB/ BC(A) (RCS)	DSS/SNPB/ BC (SFP)
NAME	JMcHale	MWater	DAlley	YLi	JPeralta	EOesterle	JDean RLukes
DATE	07/27/16** 09/26/16 (revised)*	08/01/16**	04/25/16*	07/27/16** 09/13/16 (revised)*	08/30/16**	08/06/16**	08/31/16** 03/06/17 (revised)*
OFFICE	DSS/SBPB/ BC	DE/EPNB/ BC (Section 2.2.4)	DE/EMCB/ BC (RSD)	DSS/SRXB/ BC(A) (CAP)	DSS/SNPB/ BC (Codes)	DRA/ARCB/ BC (HP)	DSS/STSB/ BC(A)
NAME	RDennig	DAlley	JQuichocho	EOesterle	JDean	UShoop	JWhittman
DATE	08/24/16**	07/28/14**	10/28/16** 11/02/16 (additions)*	10/24/16** 02/06/17 (revised)*	08/31/16**	07/29/16** 10/04/16 (additions)*	06/06/17
OFFICE	OGC – NLO	NRR Tech. Editor***	DORL/ LPL2-2/BC	DORL/D	NRR/D(A)	DORL/ LPL2-2/PM	
NAME	STurk	CCHU	UShoop	ABoland/KBrock	BHolian	FSaba	
DATE	06/05/17	07/14/17*	08/02/17	08/02/17	08/14/17	08/14/17	

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