October 3, 2005

Mr. Karl W. Singer
Chief Nuclear Officer and
Executive Vice President
Tennessee Valley Authority
6A Lookout Place
1101 Market Street
Chattanooga, TN 37402-2801

SUBJECT: BROWNS FERRY NUCLEAR PLANT, UNITS 2 AND 3 — REQUEST FOR ADDITIONAL INFORMATION FOR EXTENDED POWER UPRATE (TS-431) (TAC NOS. MC3743 AND MC3744)

Dear Mr. Singer:

By letter to the U. S. Nuclear Regulatory Commission (NRC) dated June 25, 2004, as supplemented by letters dated February 23, April 25, and June 6, 2005, Tennessee Valley Authority (the licensee) submitted an amendment request for Browns Ferry Nuclear Plant, Units 2 and 3. The proposed amendments would change the Units 2 and 3, operating licenses to increase the maximum authorized power level from 3458 to 3952 megawatts thermal. This change represents an increase of approximately 15 percent above the current maximum authorized power level. The proposed amendments would also change the Units 2 and 3 licensing bases and associated Technical Specifications to revise the credit for overpressure from 3 pounds per square inch gage (psig) for short-term and 1 psig for long-term, to 3 psig for the duration of a loss-of-coolant accident, and revise the maximum ultimate heat sink temperature.

The NRC staff finds that a response to the enclosed request for additional information is needed before we can complete the review. This request was discussed with your staff on August 29, 2005, and it was agreed that a response would be provided within 75 days of the issuance of this letter. If you have any questions, please contact me at (301) 415-2315.

Sincerely,

/RA/
Eva A. Brown, Project Manager, Section 2
Project Directorate II
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket Nos. 50-260 and 50-296

Enclosure: As stated

cc w/encl: See next page

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SUBJECT: BROWNS FERRY NUCLEAR PLANT, UNITS 2 AND 3 — REQUEST FOR ADDITIONAL INFORMATION FOR EXTENDED POWER UPRATE (TS-431) (TAC NOS. MC3743 AND MC3744)

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REQUEST FOR ADDITIONAL INFORMATION

EXTENDED POWER UPRATE (EPU)

TENNESSEE VALLEY AUTHORITY (TVA)

BROWNS FERRY NUCLEAR PLANT (BFN), UNITS 2 AND 3

DOCKET NOS. 50-260 AND 50-296

EMCB-C

Flow Accelerated Corrosion (FAC)

1. The FAC monitoring program includes the use of a predictive method to calculate the wall thinning of components susceptible to FAC. Provide a sample list of components for which wall thinning is predicted and measured by ultrasonic testing or other method. Include the initial wall thickness (nominal), current (measured) wall thickness, and a comparison of the measured wall thickness to the thickness predicted by the CHECWORKS™ FAC model.

2. EPU will affect several process variables that influence FAC. Identify the systems that are expected to experience the greatest increase in wear as a result of EPU and discuss the effect of individual process variables (i.e., moisture content, temperature, oxygen, and flow velocity) on each system identified.

Protective Coating Systems

3. TVA's (the licensee's) February 23, 2005, response states,

   Previous testing was performed which bounded peak accident conditions for all but one specific coating configuration. Therefore, TVA is performing confirmatory testing to ensure that all qualified coating configurations have been tested.

   In regards to this statement provide a discussion explaining what the specific coating configuration is, how large the affected area is, what specific testing was performed, the results of the confirmatory testing, and how the confirmatory testing is correlated to the coating's original design basis accident qualification.

EEIB-B

1. Address and discuss the following points:

   a. Identify the nature and quantity of Mega volt-amp reactive (MVAR) support necessary to maintain post-trip loads and minimum voltage levels.

   b. Identify what MVAR contributions the BFN units are credited for providing to the grid.

c. After the power uprate, identify any changes in MVAR associated with Items a and b above.

d. Address the compensatory measures that the licensee would take to compensate for the depletion of the nuclear unit MVAR capability on a grid-wide basis.

e. Evaluate the impact of any MVAR shortfall listed in Item d above on the ability of the offsite power system to maintain minimum post-trip voltage levels and to supply power to safety buses during peak electrical demand periods. The subject evaluation should document information exchanges with the transmission system operator.

2. Page 6-1 of Enclosure 4 of the June 25, 2004, submittal states that the study documented that no additional changes are required for BFN's offsite power system to continue to meet Title 10 the *Code of Federal Regulations* (10 CFR) Part 50, Appendix A, General Design Criteria (GDC)-17 requirements. Because the BFN construction permits were issued prior to the May 21, 1971, effective date of the GDC, compliance to these criteria may not be required as part of the BFN Units 2 and 3 licensing basis.

   State whether BFN Units 2 and 3 is consistent with GDC-17 or the Atomic Energy Commission Criterion 39.

3. The submittal states that transmission system operating guides will be issued to the load dispatcher prior to EPU operation, detailing any system operating constraints and any actions that may be required, including prompt communication with the control room. What protocol has been established with the transmission system operator to communicate to the licensee the availability of the transmission lines to provide sufficient voltage following a plant trip or when voltages would not be adequate?

4. Provide in detail and compare the **existing ratings** with the uprated ratings and the effect of the power uprate on the following equipment:

   a. Main generator rating and power factor
   b. Isophase bus, and modifications to the cooling system
   c. Detailed description of the replaced main power transformers
   d. Unit Auxiliary/Start-up transformers
   e. Main Generator breaker

5. Provide the list of loads affected by the power uprate change. Identify the motor loads before and after the power uprate change.

6. Provide the coping duration and recovery time expected from a station blackout (10 CFR 50.63).

7. Page 6-2 of Enclosure 4 of the June 25, 2004, submittal and Page 6-2 of Enclosure 5 of the June 25, 2004, submittal state that Units 1 and 2 share four independent safety-related diesel generator units coupled as an alternate source of power, to four

independent 4160 volt buses. Have the design and operation changed since Unit 1 was shut down in 1985? Describe the onsite alternating current power system for Units 2 and 3.

EMCB-A

1. Section 10.7, Plant Life, in Enclosure 4 of the June 25, 2004, submittal, identifies irradiation-assisted stress-corrosion cracking (IASCC) as a degradation mechanism influenced by increases in neutron fluence and reactor coolant flow. This section indicates that the current inspection strategy for reactor internal components is expected to be adequate to manage any potential effects of EPU operating conditions. Note 1 in Matrix 1 of Section 2.1 of RS-001, Revision 0 indicates that guidance on the neutron irradiation-related threshold for IASCC in boiling-water reactors (BWRs) is in Boiling-Water Reactor Vessel and Internals Program (BWRVIP) report BWRVIP-26. The "Final License Renewal SER [Safety Evaluation Report] for BWRVIP-26," dated December 7, 2000, states that the threshold fluence level for IASCC is 5×10^{20} n/cm^2 (E > 1 MeV).

   Identify the vessel internal components whose fluence at the end of period of operation with the EPU operating conditions will exceed the threshold level and become susceptible to cracking due to IASCC. For each vessel internals component that exceeds the IASCC threshold, either provide an analysis that demonstrates failure of the component will not result in the loss of the intended function of the reactor internals or identify the inspection program to be utilized to manage IASCC of the component. Identify the scope, sample size, inspection method, frequency of examination and acceptance criteria for the inspection programs.

EMEB-B

1. Discuss TVA's plans to implement Inservice Testing (IST) Programs that incorporate appropriate changes in light of applicable EPU operating conditions. In particular, discuss, with examples, the evaluation of the impact of EPU conditions on the performance of safety-related pumps, power-operated valves, check valves, and safety or relief valves, including consideration of changes in ambient conditions and power supplies (as applicable), and to indicate any resulting adjustments to the IST Programs resulting from that evaluation.

2. In Section 3.3.5, Flow Induced Vibration, of Enclosure 4 of the submittal dated June 25, 2004, states that a detailed evaluation will be performed to examine steam dryer components susceptible to failure under EPU conditions. The report indicates that any necessary modifications will be made prior to EPU operation. The report concludes that flow induced vibration effects are expected to remain within acceptable limits for EPU operation. Provide the basis for this conclusion.

3. Section 3.7, Main Steam Isolation Valves, of Enclosure 4 of the June 25, 2004, submittal states that the 24-percent increase in steam-flow rate will result in a slightly faster closure time for the main steam isolation valves (MSIVs). Describe the basis for the assumption that stroke time will remain with prescribed limits using design, test, and operational experience of the MSIVs.

4. Section 4.1.3, Containment Isolation, of Enclosure 4 of the June 25, 2004, submittal states that parameters for air-operated valves (AOVs) and solenoid-operated valves (SOVs) were reviewed, and no changes to the functional requirements of any AOVs or SOVs were identified as a result of EPU operating conditions. Discuss, with examples, the evaluation of safety-related AOVs and SOVs used for containment isolation and other safety functions for potential impact from EPU operation.

5. Section 4.1.4, Generic Letter (GL) 89-10 Program, of Enclosure 4 of the June 25, 2004, submittal states that process and ambient parameters for motor-operated valves (MOVs) were reviewed, and no changes to the functional requirements of GL 89-10 MOVs were identified as a result of EPU operating conditions In support of the EPU review, discuss with examples its evaluation of safety-related MOVs for the potential impact from EPU operation, including the impact of increased process flows on operating requirements and increased ambient temperature on motor output.

6. Section 4.1.6, GL 95-07, of Enclosure 4 of the June 25, 2004, submittal states that MOVs used for containment or high energy line break isolation have been reviewed for the effects of operations at EPU conditions, including pressure locking and thermal binding. Discuss, with examples, the evaluation of safety-related power-operated gate valves in light of any changes in ambient temperature on the potential for pressure locking or thermal binding resulting from EPU operation.

7. Section 10.4.3, Main Steam Line, Feedwater and Reactor Recirculation Piping Flow Induced Vibration Testing, of Enclosure 4 of the June 25, 2004, submittal discusses the plans for vibration monitoring during initial plant operation for the new EPU operating conditions. Discuss in more detail, the procedures for avoiding adverse flow effects during power escalation and after achieving EPU conditions, including specific hold points and duration, inspections, plant walkdowns, vibration data collection methods and locations, planned data evaluation, and decision criteria for reducing plant power level or initiating plant shutdown.

8. In the submittal dated February 23, 2005, TVA lists modifications planned to support EPU operation on pages E1-21 to 25. Discuss the modifications planned to safety-related pumps and valves, and the actions to provide assurance of their capability to perform the applicable safety functions under EPU conditions.

9. In the submittal dated February 23, 2005, the licensee states on page E1-28 that acoustical circuit analyses have been developed to identify the contributions to flow-induced vibration effects from main steam line components, junctions, and connections. Discuss the capability of such analyses to identify the excitation sources for flow-induced vibration effects in light of recent industry experience, and address the possible alternative methods to identify excitation sources.

10. In the submittal dated February 23, 2005, the licensee states on page E1-29 that TVA had performed a detailed peer review of the General Electric Steam Dryer load definition methodology and analysis, and that the peer review had provided TVA with assurance that all phases of the analysis were adequate. Describe the design-load definition for the steam dryers, and the basis for the adequacy of the load definition.

11. On page E1-28 of the submittal dated February 23, 2005, the licensee states that the uncertainty in its steam dryer analysis will be reduced by the collection of plant-specific data during power ascension. On page E1-32, the licensee states that benchmarking of the acoustic circuit analysis for determining plant-specific loads is in process against a scale model test facility. Provide the details of acoustic circuit methodology and analysis, including validation, results, and uncertainty range of the methodology and analysis. Also, discuss the modifications made to its acoustic circuit model based on lessons learned from recent industry operating experience.

12. On page E1-30 of the submittal dated February 23, 2005, the licensee states that power ascension information will be collected at each of the EPU power ascension test plateaus and compared against the stresses in the design analysis of record. Discuss the specific process for collecting, evaluating, and incorporating plant data into the design stress analysis for the steam dryers during the planned EPU power ascension.

13. On page E1-32 of the submittal dated February 23, 2005, the licensee lists proposed modifications to the steam dryers based on lessons learned from recent BWR dryer modifications. Provide detailed descriptions and diagrams of the proposed modifications to the steam dryers. Also, describe the stress analysis performed for the modified steam dryers, and the resulting changes in predicted stress in comparison to the licensee's acceptance criteria at significant locations on the steam dryers.

14. On pages E1-34 to 37 of the submittal dated February 23, 2005, the licensee discusses the potential impact of temperature changes from resulting from EPU operation mechanical equipment environmental qualification. The discussion focuses on the impact of temperature changes on non-metallic materials. Discuss the evaluation and potential impact of temperature changes on motor output of applicable safety-related MOVs resulting from EPU operation.

IPSB-A

1. Table 1 of the April 25, 2005, submittal provides a comparison of the proposed EPU testing program to the original startup testing described in Updated Final Safety Analyses Report (UFSAR) 13.5.2.3. Table 1, STP 10, describes the intermediate range monitor (IRM) Calibration/Performance test. During the initial test, the IRM-average power range monitor (APRM) overlap was checked and the IRM gains adjusted, as necessary, to improve the IRM system overlap between the source range monitors and IRMs. This adjustment was performed after the APRM heatup calibration and after the first heat balance calibration of the APRMs. Under the 'Testing Planned for EPU' column, Table 1 states that STP-10 is an EPU startup test. However, under the 'EPU Test Conditions' column, Table 1 states that STP-10 is not a startup test, but will be done during the first controlled shutdown following APRM calibration for EPU. Clarify whether IRM Calibration/Performance is a startup test and explain whether the test is proposed to be performed during the first controlled shutdown following APRM calibration versus after the APRM heatup calibration (per the initial test). Provide justification why changing when this test is performed is acceptable and meets the intent of the original test.

2. Page E-3 of the April 25, 2005, submittal states that Table 2 demonstrates that the applicable tests in Attachments 1 and 2 (of NUREG -800, Standard Review Plan (SRP) for the Review of Safety Analysis Reports for Nuclear Power Plants LWR [Light-Water Reactor] Edition, Section 14.2.1) are addressed by the testing planned for BFN EPU implementation. However, Table 2 only provides a comparison of the steady state and transient tests from the initial BFN startup tests to those described in SRP 14.2.1. Some of the initial tests referenced in Table 2 are not proposed to be performed for EPU implementation (e.g., STP-17, 25, and 27). Further clarification is needed to explain how Table 2 demonstrates that the applicable tests of SRP 14.2.1 are addressed by the proposed EPU testing.

3. Table 2 of the April 25, 2005, submittal lists three SRP 14.2.1 tests (shield and penetration cooling systems, engineered safety feature auxiliary and environmental systems, and calibrate systems used to determine reactor thermal power) which were not part of the BFN initial startup tests, but are listed as a standard procedure. Clarify that these tests are performed whether or not an EPU is implemented, or only because of the EPU implementation.

4. Page E-8 of the April 25, 2005, submittal states that the post-modification testing (of the electro-hydraulic control (EHC) system) can be conducted by inserting simulated signals such as low EHC pressure and stop valve position and that this process has been used for the current operating configuration. Clarify whether the post modification simulated signals will be performed at EPU conditions or at the current operating configuration.

IPSB-B

1. Section 8.6, Normal Operations Off-Site Doses, of Enclosure 4 of the June 25, 2004, submittal states that radiation from shine (offsite) is not presently a significant exposure pathway and is not significantly affected by EPU. This conclusion is based on the experience of earlier 5 percent power uprates for Units 2 and 3. Also, Section 8.2.2, Offsite Doses at Power Uprate Conditions, of the Environmental Report states that N-16 activity in the Turbine Building will increase linearly with EPU.

   The magnitude of the N-16 source term in the Turbine Buildings is not a simple linear increase with reactor power. The equilibrium concentration of N-16 in the Turbine Building systems will be effected (an inverse exponential function) by the decreased decay resulting from the increased steam/feed flow between the reactor and the Turbine Building. Implementation of hydrogen injection water chemistry also increases N-16 concentrations in reactor steam independently of reactor power.

   Provide the present nominal value for the skyshine external dose component (assuming all three units operating at current licensed power levels), the corresponding estimated dose component following EPU (assuming all three units operating at the requested power, and design basis steam activity, levels). Include all parameters (i.e., flow rates system component dimensions, etc.) used in calculating these values and specify the calculational method used. Identify the limiting dose receptor (i.e., is the dose receptor a member of the public located offsite (and, therefore, subject to the dose limits of 40 CFR Part 190) or a member of the public working onsite (subject to the dose limits of

20.1301)). Describe any increases in doses for onsite spaces (i.e., Administrative offices, guard stations, etc.) continuously or routinely occupied by plant visitors or staff.

2. Section 8.5.3, Post Accident, of Enclosure 4 of the June 25, 2004, submittal states that plant specific analysis for NUREG 0737, Item II.B.2. "have been performed" but gives no results or indication they meet the NUREG 0737 acceptance criteria. For each BFN Unit 2 and 3 vital area (as defined in Item II.B.2.), provide the calculated pre-uprate and post-uprate mission doses to an operator performing vital tasks following a loss-of-coolant accident (LOCA). Verify that the mission doses to personnel in these vital areas, as well as the calculated dose estimates for personnel performing required post-accident duties in the plant's Technical Support Center, are within the dose guidelines of GDC-19 (10 CFR Part 50, Appendix A). Is restoring spent fuel cooling a vital action required to mitigate the effects of a design basis LOCA at BFN Units 2 and 3?

3. Section 8.4.2, Activated Corrosion Products, of Enclosure 4 of the June 28, 2004, submittal states that the increase in the activated corrosion product activity will be 3-percent higher than the original design basis activity, and that fission products in reactor water and offgas are well within the original design basis. Provide these calculated values and the basis for this estimated increase.

   The increased steam EPU flow is likely to result in an increased moisture carryover in the steam, resulting in an increased transport of non-volatile fission products, actinides, and activated corrosion and wear products from the reactor coolant to the balance of the plant. Provide the levels of moisture carry over expected at the EPU steaming rates, and discuss its potential impact on activity buildup and resultant dose rates in the balance of plant.

4. Section 6.3.2, Crud Activity and Corrosion Products, of Enclosure 4 of the June 25, 2004, submittal indicates that the expected increase in spent fuel pool (SFP) crud is 2-percent, based on the expected increase of crud in the reactor coolant system (RCS) due to increased feed flow. Provide a summary of this calculation. Describe the impact of a 20-percent increase in feedwater flow has on condensate demineralizer efficiency.

5. Also, the estimate of the increase in RCS activity does not appear to include pre-outage crud bursts. Recently, a number of BWRs that have implemented hydrogen water and Zinc injection chemistry, have experienced large, unprecedented, crud bursts. Describe any contingencies that will be implemented to compensate for any unexpected build-up and release of crud in Units 2 and 3.

6. Section 6.3.3, Radiation Levels, of Enclosure 4 of the June 25, 2004, submittal states that the normal radiation levels around the SFP may increase slightly, primarily during fuel-handling operations. Explain the reason for, and the magnitude of, these postulated increases in dose-rate levels in the area of the SFP. Verify that these postulated dose-rate increases will be bounded by the current radiation zone designations in the SFP area. If this postulated dose-rate increase is due to higher activation of spent fuel assemblies, discuss any effects that the storage of these spent

fuel assemblies in the SFP may have on dose rates in accessible areas adjacent to the sides or bottom of the SFP.

7. Section 8.5.2, Normal Post Operations, of Enclosure 4 of the June 25, 2004, submittal states that the post-operation radiation levels in most areas of the plant are expected to increase by no more than the percentage increase in power level. This section also states, however, that there are a few areas near the reactor water piping and liquid radwaste equipment where the expected radiation level increase could be slightly higher. Provide the specific locations of these areas where higher dose rates are predicted, give the reasons for the expected increase in radiation levels in these areas, and state the percentage increase in dose rates expected.

8. Section 8.5.1, Normal Operations, of Enclosure 4 of the June 25, 2004, submittal states that, due to the conservative shielding design, the increase in radiation levels resulting from EPU will not effect the radiation zones for the various areas of the plant. This appears to be based on an assumed linear increase in radiation source term with power level. However, the increase in N-16 activity in the turbine building is an inverse exponential function with decay time, not a linear function of reactor power. Verify that the radiation zoning in all areas containing the steam and feed systems will be unaffected by EPU.

9. Enclosure 8, Table 2 of the June 25, 2004, submittal states that the objective of test STP 1, Chemical and Radiochemical, is not applicable to EPU and is not required. The Table 1 entry for STP 1 states that "samples will be taken and measurements will be made at selected EPU power levels. . . ." Describe which samples and measurements will be made and at what power levels.

10. Enclosure 8, Table 2 of the June 25, 2004, submittal states that the objective of test STP 2, Radiation Measurements, is not applicable to EPU and is not required. The Table 1 entry for STP 2 states that "Gamma dose rate measurements. . . will be made at specific limiting locations throughout the plant. . . ." Describe the limiting locations for which measurements will be made and at what power levels.

11. Summarize the major Units 2 and 3 plant hardware or system modifications involved in the requested EPU and discuss any changes with the occupational doses associated with plant operation with the modifications installed.

SPLB-A

<u>Spent Fuel Pool Cooling and Cleanup System (SFPCCS)</u>

1. Section 10.5.5 of the UFSAR, Revision 17 dated August 30, 1999, revised the discussion from the UFSAR that was previously provided regarding the maximum SFP heat load for batch and full core offloads. In order to facilitate NRC review of the capability of the SFPCCS to perform its function for EPU conditions, provide a discussion on the safety-related systems required to maintain fuel pool cooling within design bases temperature limits.

2. For EPU conditions, explain how the SFP water temperature will be maintained below 150 degrees Fahrenheit (F) for the worst-case normal (batch) and full core offload scenarios assuming a loss of offsite power and (for the batch offload only) a concurrent single active failure considering all possible initial configurations that can exist. Include a description of the maximum decay heat load that will exist in the SFP for each case, how these heat loads were determined, such that they represent the worst-case conditions, and what the cooling capacity is for the systems that are credited, including how this determination was made. Also:

    a. Describe any operator actions that are required, how long it will take to complete these actions, and how this determination was made; and

    b. Describe the maximum core decay heat load that will exist at the onset of fuel movement, how this determination was made, how this heat load will be accommodated while also satisfying the SFP cooling requirements over the duration of the respective fuel offload scenarios, and including the situation where the SFP is isolated from the reactor vessel cavity.

3. Discuss how adequate SFP makeup capability is assured for EPU conditions in the unlikely event of a complete loss of SFP cooling capability, including how the maximum possible SFP boil-off rate compares with the assured makeup capability that exists, operator actions that must be taken, how long it will take to complete these actions and how this determination was made, and boron dilution considerations.

4. Provide justification and/or details of the evaluation which concludes that the SFP cooling and makeup systems continue to meet the requirements of draft GDC-4 for EPU conditions, in so far as it requires that reactor facilities shall not share systems or components unless it is shown safety is not impaired by the sharing.

<u>Service Water Systems</u>

5. In Section 6.4.1.1, of Enclosure 4 of the June 25, 2004, submittal regarding the emergency equipment cooling water (EECW) system, it is stated that: “EPU does not significantly increase equipment cooling water loads, and thus, the capacity of the EECW system remains adequate.” Discuss, in more detail, the impact of the proposed EPU on EECW heat loads, flow rates, and flow velocities for the worst-case conditions, including limiting assumptions, input parameters, and available margin that will remain.

6. In Section 6.4.1.1.2, of Enclosure 4 of the June 25, 2004, submittal regarding the residual heat removal service water (RHRSW) system, it is stated that:

    > The post-LOCA containment and suppression pool responses have been calculated based on an energy balance between the post-LOCA heat loads and the existing heat removal capacity of the RHR and RHRSW systems. As discussed in Sections 3.11 and 4.1.1, the existing suppression pool structure and associated equipment have been reviewed for acceptability based on this increased suppression pool temperature . . . .The RHRSW system flow rate is not changed.

Discuss in more detail, the impact of the proposed EPU on the RHRSW system heat loads (including SFP cooling considerations), flow rates, and flow velocities for the worst-case conditions, including limiting assumptions, input parameters, and available margin that will remain.

7. Provide a description of any impacts that the proposed EPU will have on the issues described in GL 89-13, “Service Water System Problems Affecting Safety-Related Equipment,” GL 96-06, “Assurance of Equipment Operability and Containment Integrity During Design Basis Accident Conditions,” and GL 96-06, Supplement 1, including the basis for your determination. In particular, confirm that the assumed heat transfer capabilities of heat exchangers are consistent with heat exchanger performance testing that has been completed in accordance with GL 89-13 and corrected for worst-case conditions; and that water-hammer and two-phase flow analyses that were completed in accordance with GL 96-06 continue to be valid.

8. For EPU conditions, provide justification and/or details of the evaluation which concludes that the safety-related service water systems will continue to meet the requirements of draft GDC-4, in so far as it requires that reactor facilities shall not share systems or components unless it is shown safety is not impaired by the sharing.

SPLB-B

1. Discuss whether any administrative controls or fire protection responsibilities of plant personnel are affected by an increase in decay heat. Also, address why an increase in decay heat will not result in an increase in the potential for a radiological release from a fire.

2. Section 6.7.1, of Enclosure 4 of the June 25, 2004, submittal states that:

> a plant-specific evaluation was performed to demonstrate safe shutdown capability in compliance with the requirements of 10 CFR 50 Appendix R assuming EPU conditions. . . The results of the Appendix R evaluation for EPU provided in Table 6-5 demonstrate that fuel cladding integrity, reactor vessel integrity, and containment integrity are maintained and that sufficient time is available for the operator to perform the necessary actions.

Upon reviewing Table 6-5, BFN Appendix R Fire Event Evaluation Results, the NRC staff was able to find references for all but the following values in the EPU submittal:

C Cladding Heatup (PCT), degrees F = 1428 (EPU)
C Suppression Pool Bulk Temperature, degrees F = 227 (EPU), # 227 (Appendix R Criteria), including Note 3
C Primary Containment Pressure, pounds per square inch gage = 13.6 (EPU)

Provide references, including appropriate extracts from the UFSAR, plant-specific Appendix R evaluation, etc., for these values in Table 6-5, including Note 4.

3. Section 6.7.1 of Enclosure 4 of the June 25, 2004, submittal states that:

> [f]or this [bounding PCT] case, the time available to the operator to open three MSRVs [main steam relief valves] is 25 minutes at the EPU conditions. The BFN Units 2 and 3 pre-EPU analysis determined the three MSRVs were required to be opened within 30 minutes. This reduction in the time available does not have any effect because the procedures will require this action to be completed within 20 minutes.

Discuss the time-line analyses, including any assumptions, that may have been made in determining that the action can confidently be accomplished within 20 minutes, such that the 5-minute reduction in available time "does not have any effect."

4. The June 6, 2005, Reply 7 of Enclosure 4, states that:

> the plant is compartmentalized and protected in accordance with Appendix R requirements such that a fire in one area will not affect the equipment in another area or, alternate shutdown paths capable of controlling each of the units are available.

Discuss whether that latter phrase "alternate . . . available" is intended as additional to the former phrase "a fire . . . area" or as a contingency if the first phrase does not apply. That is, does Volume 1 of the BFN Fire Protection Report (FPR) ensure "that a fire in one area will not affect the equipment in another area" exclusively, or does it do so only if "alternate shutdown paths capable of controlling each of the units are [not] available?"

5. Section 6.7.1 of Enclosure 4 of the June 25, 2004, submittal as supplemented by the reply dated June 6, 2005 (including the discussion for the ATRIUM-10 fuel), states that "spurious operation of HPCI [high pressure coolant injection] was reviewed in accordance with [Volume 1 of the BFN FPR]. The HPCI system was assumed to initiate at the onset of the Appendix R event, and flow at its normal flow rate. The time at which the reactor vessel water level would reach the MSLs [main steam lines] is greater than 6 minutes. Therefore, the procedures will require HPCI isolation prior to 6 minutes during an Appendix R event." Volume 1 of the BFN FPR addresses pre-EPU conditions, so the conclusion regarding the greater than 6-minute time for the reactor vessel water level to reach the MSLs presumably applies to pre-EPU conditions.

Discuss whether the conclusion with regard to the timing for isolation of HPCI still remains valid at EPU conditions.

6. Page E13-ii of Enclosure 13 of the June 25, 2004, submittal states:

> Because the BFN construction permits were issued prior to the May 21, 1971, effective date of the GDC, compliance to these criteria [i.e., the acceptance criteria contained in RS-001] is not required as part of the BFN Units 2 and 3 licensing basis.

Correspondingly, the submittal contains a modified version of Section 2.5.1.4, Fire Protection, of Insert 5 for “Section 3.2 - BWR Template Safety Evaluation” from RS-001. However, Section 1.3, Basis of the Fire Protection Plan, of Volume 1 of the BFN FPR, states the following.

> This Fire Protection Plan has been developed for BFN to satisfy the requirements of General Design Criterion (GDC)[-]3 of Appendix A to 10 CFR 50. . . On November 19, 1980, the Nuclear Regulatory Commission (NRC) published its final 10 CFR 50.48, ‘Fire Protection,’ which established fire protection requirements for operating nuclear power plants. This regulation, which imposed the requirement to have a fire protection plan to satisfy GDC 3, became effective on February 17, 1981. This regulation is applicable to BFN.

Furthermore, Section 6.7.1 presents an analysis based on the BFN FPR, which acknowledges GDC 3 as the basis for the current Fire Protection Program. Address the discrepancy between the submitted information and the FPR.

7. Some plants credit aspects of their Fire Protection System 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). Identify the specific situations and discuss to what extent, if any, the EPU affects these “non-fire-protection” aspects of the plant Fire Protection System.

SPSB- A

1. The second paragraph of Section 10.5 on Enclosure 4 of the June 25, 2004, submittal indicates that all associated plant modifications were systematically reviewed to identify their effect on the elements of the probabilistic risk assessment (PRA) model. Provide the details of these systematic reviews for Units 2 and 3, including the effect of each modification on the PRA model.

2. Provide the following information related to the treatment of a loss of offsite power (LOOP) in the PRA model:

    a. Describe how the frequencies of LOOP events were determined.

    b. Describe how the recovery of offsite power is modeled in the PRA (e.g., use of specific representative times, probabilistic convolutions).

    c. Describe how the probabilities of offsite power recovery events were determined.

    d. Describe how the probability of consequential LOOP was determined.

    e. Provide the contribution to the total core damage frequency (CDF) from consequential LOOP events.

3. In Section 10.5.2 of Enclosure 4 of the June 25, 2004, submittal, it is stated that the frequencies of loss of feedwater and loss of all condensate are expected to decrease for the post-EPU plant. Explain why.

4. Section 10.5.1 of Enclosure 4 of the Unit 1 submittal dated June 28, 2004 indicates that the Unit 1 PRA uses more detailed initiating event categories as compared to the Unit 2 and Unit 3 PRAs in order to facilitate the tracing of success criteria in the PRA model. Explain why it was not necessary to use more detailed initiating event categories in the Units 2 and 3 PRA models.

5. The following questions/requests relate to the internal flooding initiating event frequencies:

   a. For “emergency equipment cooling water (EECW) flood in reactor building – shutdown units,” the Unit 1 frequency is given as 1.2E-3. For Unit 2, this frequency is given as 1.2E-5, and for Unit 3, as 1.2E-2. Provide an explanation and bases for these widely different estimates.

   b. For the remaining flooding initiators (EECW flood in reactor building – operating unit, flood from the condensate storage tank, flood from the torus, large turbine building flood and small turbine building flood), the Unit 1 frequencies are higher than the corresponding Unit 2 and Unit 3 frequencies. Explain and provide a basis for these differences.

6. Section 10.5 of Enclosure 4 of the June 28, 2004, submittal states that the Unit 1 PRA assumes that Units 2 and 3 are operational at EPU power levels. Provide the following information related to the treatment of multi-unit interactions in the Units 1, 2, and 3 PRA models:

   a. Describe how various combinations of plant operating states (at-power, shutdown, transition) are addressed.

   b. Describe which initiating events impact more than one unit and describe how these are modeled.

   c. Identify the systems that are shared among units and describe how these shared systems are modeled in the PRA. Specifically address when credit is taken to recover failed key safety functions by using cross-connects among units.

7. Provide the detailed human reliability analysis (HRA) calculation sheets (e.g., as generated by the Electric Power Research Institute (EPRI) HRA calculator) for all human interactions ("operator actions") that (a) have a Fussell-Vesely importance measure greater than 0.005 or a risk-achievement worth greater than 2, or (b) were modified to represent the post-EPU plant.

8. Provide a discussion of large early release frequency (LERF) from external events or a basis for concluding that any increases due to EPU are not significant.

9. The frequency-weighted fractional importance to core damage of operator action HORVD2, Manual depressurization of reactor pressure vessel using MSRVs, for the post-EPU plant is 55 percent for Unit 2 and 43 percent for Unit 3 CDF. For Unit 1, the corresponding operator action appears to be HPRVD1, Operator fails to initiate depressurization, which has a frequency-weighted fractional importance to core damage of 26.7 percent. Explain, in detail, why these apparently similar events have such different importance to core damage in light of the similarity of the PRA models. Also, describe the programmatic activities (e.g., training) intended to make this operator action reliable.

10. Section 10.5.3 of Enclosure 4 of the submittal dated June 25, 2004, states:

> Recovery actions take credit for those actions performed by the on-shift personnel either in response to procedural direction or as skill-of-the-craft to recover a failed function, system or component that is used in the performance of a response action in dominant sequences.

Does this include repair of failed equipment? If yes:

a. Provide a list of repair events credited in each PRA model, including the basis for the non-recovery probabilities used.

b. How have these repair human error probabilities been adjusted as the result of EPU?

c. Provide a sensitivity of CDF and LERF to repair activities, if credited, by removing all credit for repair of failed equipment.

11. As part of its EPU submittal, the licensee has proposed taking credit (Unit 1) or extending the existing credit (Units 2 and 3) for containment accident pressure to provide adequate net positive suction head (NPSH) to the ECCS pumps. Section 3.1 in Attachment 2 to Matrix 13 of Section 2.1 of RS-001, Revision 0 states that the licensee needs to address the risk impacts of the extended power uprate on functional and system-level success criteria. The staff observes that crediting containment accident pressure affects the PRA success criteria; therefore, the PRA should contain accident sequences involving ECCS pump cavitation due to inadequate containment pressure. Section 1.1 of RG 1.174 states that licensee-initiated licensing basis change requests that go beyond current staff positions may be evaluated by the staff using traditional engineering analyses as well as a risk-informed approach, and that a licensee may be requested to submit supplemental risk information if such information is not submitted by the licensee. It is necessary to consider risk insights, in addition to the results of traditional engineering analyses, while determining the regulatory acceptability of crediting containment accident pressure.

Considering the above discussion, please provide an assessment of the credit for containment accident pressure against the five key principles of risk-informed decision-making stated in RG 1.174 and SRP Chapter 19. Specifically, demonstrate that the proposed containment accident pressure credit meets current regulations, is consistent

with the defense-in-depth philosophy, maintains sufficient safety margins, results in an increase in core-damage frequency and risk that is small and consistent with the intent of the Commission's Safety Goal Policy Statement, and will be monitored using performance measurement strategies. With respect to the fourth key principle (small increase in risk), provide a quantitative risk assessment that demonstrates that the proposed containment accident pressure credit meets the numerical risk acceptance guidelines in Section 2.2.4 of RG 1.174. This quantitative risk assessment must include specific containment failure mechanisms (e.g., liner failures, penetration failures, primary containment isolation system failures) that cause a loss of containment pressure and subsequent loss of NPSH to the ECCS pumps.

12. Explain how the impact of increasing the ultimate heat sink temperature from 91 to 95 degrees F has been incorporated into the PRA. Which PRA basic events are affected by this change?

13. The existing fire risk evaluations are based on the EPRI Fire Induced Vulnerability Evaluation (FIVE) methodology, which uses a quantitative screening criterion of 10^{-6} per year. This screening criterion appears too large because the core-damage frequency from internal events is of the same order of magnitude. As the fire risk evaluations for Units 2 and 3 have not been updated since the individual plant external event evaluation was performed, provide an updated FIVE analysis for each unit that reflects the post-EPU plant configuration and uses an appropriate screening criterion.

14. Enclosure 7 of the submittal dated June 25, 2004, identifies planned modifications of the drywell building steel (building steel beams and connections), main steam supports, and torus attached piping (supports and snubbers) due to the EPU conditions. With respect to these planned modifications, address the following issues:

    a. Confirm that these planned modifications will not change the high confidence of low probability of failure values used in the seismic margins analysis.

    b. Describe the impact that the proposed modifications have on the probability distribution function of containment strength used in the LERF analysis.

15. TVA has previously requested a full-scope application of an alternative source term. As part of this request, it was proposed that the standby liquid control system be used to help control suppression pool pH during severe accidents. Has suppression pool pH control been credited in the LERF analysis? If so, provide the details.

16. Describe the operator actions considered in the estimation of LERF. How are the Severe Accident Management Guidelines accounted for in the LERF analysis?

17. Address the questions in the SRP, Chapter 19, Table III-1 concerning low power and shutdown PRA.

18. Provide an assessment of the PRA’s technical adequacy as discussed in RG 1.200. Note that it is acceptable to perform the assessment by making either (a) a direct assessment against the requirements of the American Society of Mechanical Engineers (ASME) PRA Standard Addendum A (ASME SA-Ra-2003), or (b) a self-assessment

using the guidance issued on August 16, 2002, by the Nuclear Energy Institute (NEI) that supplements NEI 00-02.

19. Provide an explanation the following:

    a. Why does CDF decrease and LERF increase (EPU compared to baseline) for inadvertent opening of one MSRV, inadvertent opening of two or more MSRVs and flood from torus?

    b. For "flood from torus," why is the LERF increase greater than the magnitude of the CDF decrease?

    c. For Unit 2, why does CDF decrease and LERF increase for "EECW flood in reactor building – shutdown unit?"

    d. For Unit 3, why does CDF decrease and LERF increase for "EECW flood in reactor building – operating unit?"

20. Explain why the CDF estimates for some initiating events have notably increased for the post-EPU plant as compared to the pre-EPU plant. Relate the explanation to one or more of the PRA model changes identified in Section 10.5 of Enclosure 4 of the June 25, 2004, submittal. As a minimum, increases in the CDF estimates for the following initiating events must be explained:

    a. Loss of 500 kilovolt (kV) to one unit

    b. Loss of condenser heat sink

    c. Turbine trip with bypass

    d. Small turbine building flood (Unit 3 only)

21. Explain why the CDF estimates for some initiating events have decreased for the post-EPU plant as compared to the pre-EPU plant. Based on the description (Section 10.5 of Enclosure 4 of the June 25, 2004, submittal) the PRA model changes made to reflect the post-EPU plant configuration, the NRC staff noted a slight decrease in the CDF estimate for any initiating event. Specifically:

    a. Inadvertent opening of one MSRV

    b. Inadvertent opening of two or more MSRVs (Unit 2 only)

    c. Total loss of offsite power

    d. Loss of raw cooling water (Unit 2 only)

    e. Small LOCA

    f. EECW flood in reactor building - shutdown unit (Unit 2 only)

g. EECW flood in reactor building - operating unit

h. Flood from the condensate storage tank

i. Flood from the torus

j. Large turbine building flood (Unit 2 only)

22. Provide a list of the significant basic events contained in the PRA logic model (including both the basic event name, the basic event description, the Fussell-Vesely importance measure and the Risk Achievement Worth) for the post-EPU plant configuration. Note that term “significant basic event” is defined in RG 1.200, Appendix A, Table A-1, Index Number 2.2.

23. Identify the key sources of uncertainty and the key assumptions in the PRA. Note that the terms “key source of uncertainty” and “key assumption” are defined in RG 1.200, Appendix A, Table A-1, Index Number 2.2.

IROB-B

1. Describe how the proposed EPU will change the plant emergency and abnormal operating procedures.

2. 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.

3. Describe any changes the proposed EPU will have on the operator interfaces for control room controls, displays, and alarms. For example, what zone markings (e.g., normal, marginal and out-of-tolerance ranges) on meters will change? What setpoints will change? How will the operators know of the change? Describe any controls, displays, or 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.

4. Describe any changes to the safety parameter display system resulting from the proposed EPU. How will the operators be informed of the changes?

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