May 5, 2005

Mr. L. William Pearce
Vice President
FirstEnergy Nuclear Operating Company
Beaver Valley Power Station
Post Office Box 4
Shippingport, PA 15077

SUBJECT: BEAVER VALLEY POWER STATION, UNIT NOS. 1 AND 2 (BVPS-1 AND 2) - REQUEST FOR ADDITIONAL INFORMATION (RAI) - EXTENDED POWER UPRATE (EPU) (TAC NOS. MC4645 AND MC4646)

Dear Mr. Pearce:

By letter to the U.S. Nuclear Regulatory Commission (NRC) dated October 4, 2004, FirstEnergy Nuclear Operating Company (the licensee) submitted a license amendment request for BVPS-1 and 2 to change the operating licenses to increase the maximum authorized power level from 2689 megawatts thermal (MWt) to 2900 MWt which represents an increase of approximately 8 percent above the current maximum authorized power level. The NRC staff has determined that the additional information contained in the enclosure to this letter is needed to complete its review. As discussed with your staff, we request your response within 60 days of receipt of this letter, in order for the NRC staff to complete its scheduled review of your submittal.

If you have any questions, please contact me at 301-415-1402.

Sincerely,

/RA/

Timothy G. Colburn, Senior Project Manager, Section 1
Project Directorate I
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket Nos. 50-334 and 50-412

Enclosure: RAI

cc w/encl: See next page

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ACCESSION NO. ML051160069 *Input received. No substantive changes made.

OFFICE	PDI-1/PM	PDI-2/LA	SRXB/SC(A)	PDI-1/SC
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DATE	4/28/05	5/3/05	04/04/05	5/5/05

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REQUEST FOR ADDITIONAL INFORMATION

RELATED TO FIRSTENERGY NUCLEAR OPERATING COMPANY (FENOC)

BEAVER VALLEY POWER STATION, UNIT NOS. 1 AND 2 (BVPS-1 AND 2)

EXTENDED POWER UPRATE (EPU)

DOCKET NOS. 50-334 AND 50-412

By letter dated October 4, 2004 (Reference 1), Agencywide Documents Access and Management System (ADAMS), Accession No. ML042920300, FENOC (licensee) proposed changes to the BVPS-1 and 2 operating licenses to increase the maximum authorized power level from 2689 to 2900 megawatts thermal (MWt) rated thermal power (RTP) or approximately 8%. The Nuclear Regulatory Commission (NRC) staff has reviewed the licensee's application against the guidelines in the EPU review standard (Reference 2) and determined that it will need the additional information identified below to complete its review.

General Questions

1. Please provide a table listing the key assumptions and input parameter values for all accident analyses in the licensing bases of BVPS-1 and 2, both before and following the proposed power uprate.

2. Please provide a summary table listing all accident analyses in the licensing bases of BVPS-1 and 2 and how they're shown to meet applicable acceptance criteria under the conditions of the proposed license amendment (e.g., by re-analysis, by evaluation, by being bounded by current licensing basis analyses, or by not being affected by the requested license amendment).

3. Provide summary, quantitative information to show how the proposed EPU would be accomplished (the heat balance discussion in Section 8.2 deals only with the balance-of-plant (BOP) equipment).

4. In the BVPS-1 and 2 EPU submittal, it is stated that the thermal design flow is reduced relative to the original power capability working group parameters, and that this reduction is evaluated and implemented as part of a previous project, not as an EPU project change. Please provide more detailed background information to support this statement.

5. Table 9.1-1 shows that the reactor coolant system (RCS) temperature-related EPU power capability working group values are specified as ranges of values. Provide a more detailed rationale for your selection of initial plant conditions for each transient analyzed to achieve the most conservative results.

Enclosure

6. BVPS-1 and 2 are provided with loop isolation valves in each of the three RCS loops. Please indicate whether they are credited in the analysis of any transients or design-basis events. If so, please explain.

7. Discuss the design basis of the pressurizer safety valve (PSV) sizing at BVPS-1 and 2. Are they sized according to the method described in NUREG-0800, “Standard Review Plan [SRP] for the Review of Safety Analysis Reports for Nuclear Power Plants,” Section 5.2.2, which is based upon the assumption of a reactor trip on the second reactor trip signal? Verify the adequacy of the PSVs at BVPS-1 and 2 for the EPU conditions using methods that are consistent with the current licensing basis for BVPS-1 and 2.

8. Provide a quantitative tabulation of the time needed for plant cooldown to cold shutdown conditions (natural circulation cooldown using only safety grade equipment), and for plant cooldown per the requirements of Title 10 of the *Code of Federal Regulations* (10 CFR), Part 50, Appendix R (regarding fire protection), for each of the Beaver Valley units both at the EPU power level and at the current power level.

9. Please provide a tabulation of all computer codes and methodologies used in the re-analyses to support the EPU; and, for each, indicate the NRC approval status, any conditions or limitations on their use, and how the limitations, if any, are applied in the EPU analyses for BVPS-1 and 2.

10. Provide a tabulation of the thermal design parameters and compare them to values assumed in safety analyses to demonstrate that the safety analyses assumptions are conservative.

11. Please confirm that only safety grade systems and components are credited in the re-analyses of all transients and accidents in the EPU report for BVPS-1 and 2.

12. Provide a quantitative evaluation of the impacts of the EPU on the ability of BVPS-1 and 2 to cope with a station blackout (SBO) event. The evaluation should address the capacities of the condensate storage tank, turbine-driven auxiliary feedwater pump, station batteries, and backup air supplies for air-operated valves for decay heat removal and RCS cooldown during the time period of an SBO.

13. Matrix 8 of RS-001, NRC’s review standard for extended power uprates, lists new fuel and spent fuel storage as areas of review, with respect to General Design Criterion (GDC) 62, “Prevention of criticality in fuel storage and handling.” It is necessary to show that the assumptions in the BVPS-1 and 2 new fuel and spent fuel pool criticality analyses of the current licensing basis would be valid for EPU conditions.

    a. Do the current spent fuel pool criticality licensing bases of BVPS-1 and 2 include a commitment to 10 CFR 50.68? Has an exemption from the requirements of 10 CFR 70.24 been requested and approved? If so, please explain how the conditions in this exemption will not be violated as a result of the proposed EPU.

    b The BVPS-1 and 2 Technical Specification (TS) Bases refer to the use of Westinghouse Topical Report, WCAP-14416, as part of the licensing basis.

Address how the current criticality analyses are still bounding, given the higher enrichments needed for the EPU, and the non-conservatisms identified in the topical report. (References: Letter dated July 27, 2001, to Westinghouse from the NRC regarding axial burnup bias; Regulatory Issue Summary, RIS-01-012 dated May 18, 2001, "Nonconservatism in Pressurized Water Reactor Spent Fuel Storage Pool Reactivity Equivalencing Calculations."

c. Address the effects of the changes in fuel characteristics and operating strategy on new fuel and spent fuel criticality analyses (e.g. how does the change in operation affect the assumptions used for burnup profiles/burnup credit? How does the new fuel geometry/characteristics affect criticality analyses?)

Sections 3.2, 5.3.6, and 9.1 — Overpressure Protection During Power Operation

1. One of the most significant impacts of any power uprate is on overpressure scenarios. The BVPS-1 and 2 EPU submittal does not address the analysis guidelines of SRP, Section 5.2.2, "Overpressure Protection," specifically SRP 5.2.2, Section II.A. Historically, virtually all Westinghouse plants have been licensed referring to WCAP-7769 (which explicitly identifies BVPS-1and 2, operating at 2774 MWt, as plants covered by the report) as the basis for meeting this SRP guideline. However, BVPS-1 and 2, operating at the proposed uprated power of 2900 MWt, no longer fall in a class explicitly covered by WCAP-7769. The analyses described in the EPU application, Section 5.3.6.3, do not satisfy the SRP 5.2.2 guidelines. The NRC staff's safety evaluation report (SER) related to WCAP-7769 (Reference 6) limits the scope of its approval. Please provide either (1) BVPS-1 and 2 analyses per SRP 5.2.2, II.A guidelines, or (2) identify existing analyses that apply to BVPS-1 and 2 which comply with SRP 5.2.2 guidelines.

Sections 3.2.1, 4.4, and 9.22.3 — Functional Design of the Control Rod Drive System

1. With respect to the analysis for uncontrolled rod cluster control assembly (RCCA) bank withdrawal at power, Tables 5.3.3-1A and 5.3.3-1B, provide the time sequence of events for BVPS-1 and 2, respectively. In the analysis for a slow RCCA withdrawal, the overtemperature ΔT trip is credited with terminating the event. Both tables indicate the RCCAs start to fall within 2 seconds of overtemperature ΔT trip condition being reached. Table 14D-3 of the BVPS-1 Updated Final Safety Analysis Report (UFSAR) states there is a 6-second delay associated with the overtemperature ΔT trip. Table 15.0-4 of the BVPS-2 UFSAR states there is a 10-second delay associated with the overtemperature ΔT trip. What changes have been made which reduced these delay times?

Sections 4.3 and 6.0 — Fuel System Design

1. In Section 4.3, “Fuel Assemblies,” of the licensee’s EPU request it is stated, “...seismic and LOCA [loss-of-coolant accident] analyses were performed for the fuel assemblies for the homogenous core of RFA [robust fuel assemblies] (w/IFMs [intermediate flow mixing]).” In Section 6, “Fuel Analysis,” it is stated, “...previously burned VANTAGE 5H fuel assemblies may be reinserted...” and “...reinserting VANTAGE 5H fuel assemblies into the core will be confirmed during the normal reload design process...” At EPU conditions, how are the seismic and LOCA analyses affected by the non-homogenous core of RFA and VANTAGE 5H fuel assemblies?

2. In Section 4.3, of the licensee’s EPU request, it is stated, “...the best estimate flow per fuel assembly will be slightly higher than the best estimate flow per assembly in previous analysis.” What is the mechanism for the increased flow? Is this applicable to both units or just BVPS-1 with the replacement steam generators (RSGs)?

3. In Section 4.3, of the licensee’s EPU request, it is stated, “...the fuel assembly holddown spring capacity was verified to still be acceptable.” Did that analysis include the effects of fuel assembly growth due to irradiation and the increased growth expected at EPU conditions? Did that analysis include the effects of elevated core exit temperature?

4. The licensee’s EPU request did not address fuel rod bowing considerations. With the increased irradiation of fuel rods expected as a result of EPU conditions, please provide an analysis of the effect of EPU conditions on fuel rod bowing.

5. In Section 6, Subsection, <u>Grid Assemblies</u>, of the licensee’s EPU request, it is stated that IFM grids “... must accomplish this (*promote flow mixing*) without inducing clad wear beyond established limits. The IFMs must avoid interactive damage with grids from neighboring fuel assemblies during core loading and unloading conditions.” Please provide an analysis on how these criteria are met, especially considering the increased flow per assembly at EPU conditions with respect to inducing clad wear beyond established limits.

6. In Section 6, Subsection, <u>Guide Thimble and Instrument Tubes</u>, of the licensee’s EPU request, it is stated that RFA thicker-walled thimble and instrumentation tubes, relative to VANTAGE 5H fuel assemblies improve “...stiffness and address incomplete rod insertion (IRI) considerations.” Does the licensee anticipate EPU conditions to exacerbate IRI considerations? Given reinserted VANTAGE 5H fuel assemblies will not have the thicker-walled thimble and instrumentation tubes, how does the licensee intend to control these reinserts with respect to IRI considerations at EPU conditions?

7. In Section 6, Subsection, <u>Mechanical Performance</u>, of the licensee’s EPU request, it is stated, “...the addition of the three IFM grids do not significantly influence the RFA fuel assembly structural characteristics that were determined by prior mechanical testing.” What was the physical configuration of the RFAs that were subjected to mechanical testing? What mechanical testing was conducted? What structural characteristics were determined by the mechanical testing? How does the mechanical testing that was performed correlate to the expected EPU conditions?

8. In Section 6, Subsection, <u>Core Components,</u> of the licensee’s EPU request, it is stated, “...core components for Beaver Valley are designed to be compatible with the RFA and

VANTAGE 5H fuel assembly designs." How are the core components affected by EPU conditions? Please address each core component separately.

9. In Section 6.3.3.3, "Clad Stress and Strain," the licensee indicates margin-to-stress and -strain limits are reduced at EPU conditions. The licensee concludes that stress and strain limits are met for EPU conditions. The licensee does not address the impact of the reduced stress and strain margins on fatigue cycles. Please provide an evaluation of the impact on the fatigue life of RFA and VANTAGE 5H fuel assemblies at EPU conditions.

10. In Section 6.3.3.2, "Clad Corrosion," the licensee indicates margin-to-corrosion and hydrogen embrittlement limits are reduced at EPU conditions due to increased clad temperature. The licensee concludes that corrosion and hydrogen embrittlement limits are met for EPU conditions. The licensee does not address the impact of the increased clad temperature on the propensity for crud deposition on the cladding or the potential for increased chemical plate-out on the cladding due to the increased cladding temperature. Please provide an evaluation on propensity for crud deposition on the cladding and the potential for increased chemical plate-out on the cladding at EPU conditions.

11. In Section 6, Subsection, <u>Fuel Assembly Design,</u> of the licensee's EPU request, it is stated, "RFA-2 design includes an enhanced mid grid design that results in increased mid grid contact area with the fuel rod." This increased mid grid contact with the fuel rod is intended to provide improved fretting wear margin. Does the licensee anticipate EPU conditions to exacerbate fretting wear considerations? Does the licensee anticipate the increased flow due to the RSGs to exacerbate fretting wear considerations for BVPS-1? Does the licensee anticipate a synergy between RSG effects and EPU conditions to exacerbate fretting wear considerations for BVPS-1? Given reinserted VANTAGE 5H and RFA fuel assemblies will not have the improved fretting wear margin, how does the licensee intend to control these reinserts with respect to fretting wear considerations?

12. What post-irradiation tests and inspections are being incorporated to verify that operation at EPU conditions does not have an adverse impact on fuel design?

<u>Section 5.2.2</u> <u>LOCA</u>

1. Please provide the moderator-density feed back curve used in the small-break LOCA (SBLOCA) analyses. Also, what is the moderator temperature coefficient (MTC) used to generate the most limiting curve for SBLOCA analyses. What uncertainty is applied to this curve. If a positive MTC characterizes the units, please provide the core normalized power plots for the limiting breaks.

2. What uncertainties in head and flow are applied to the high-pressure safety injection (HPSI) head flow curve provided in Table 5.2.2-2?

3. Please provide a reference for, or an analysis of, the case of a severed emergency core cooling system (ECCS) line. Also, please provide the head versus flow curve for flow into the intact loops for this case. With a discharge coefficient of 1.0 on the pump side, what coefficient or break size on the discharge leg side of the break is the most limiting

size? What is the break size that will preclude accumulator actuation under these conditions?

4. What is the capacity of the condensate storage tank (CST)? How long can the operators delay a cooldown for the very small breaks such that shutdown cooling can be initiated prior to exhaustion of the CST? What operator guidance is provided to assure shutdown cooling can be successfully initiated following all small breaks? If the pressurizer refills during the cooldown trapping hot RCS water in the pressurizer, please explain what equipment is used to initiate shutdown cooling (reduce RCS pressure) should the RCS repressurize prior to achieving the entry temperature for operation of the residual heat removal system. If a fill and drain method is employed, is there sufficient CST inventory to initiate shutdown cooling? Please explain.

5. The break spectrum of 1.5-, 2.0-, 3.0-, and 4.0-inch diameter breaks (0.012, 0.022, 0.049 and 0.087 ft^2) is much too coarse to assure that peak cladding temperature (PCT) and peak clad oxidation are captured. Since the accumulators inject during the 2-inch break for BVPS-2, please provide an analysis of a slightly smaller break where the RCS pressure decreases to just above the accumulator actuation pressure of 575 psia. What reduction in accumulator pressure would be necessary to preclude accumulator actuation for the 2-inch break?

5a. Since the 3-inch break for BVPS-1 is limiting and the PCT is terminated by accumulator injection, please reduce the break size such that the RCS pressure remains just above the accumulator actuation pressure and present the results. Also, please explain why the PCT would not increase for break sizes between 3 and 4 inches.

6. The mixture level plot for the 2-inch breaks between 1400 and 2200 seconds looks numerically unstable. Please explain the reason for the erratic behavior in the mixture level plots during this time frame. Please provide the liquid level plot in the core for this break. Please reduce the time step for this case and show the mixture level for this case is converged. What is the PCT if the erratic jumps in mixture level are smoothed (extrapolate the smooth decrease in level from 1000 to 1400 through to 2200 seconds)? What time steps were used in the SBLOCA analyses?

7. For the 2-inch break, Tables 5.2.2-4 A and B identify the timing for loop seal clearing. Please identify how many loop seals clear (and any residual liquid remaining) for each break size. If more than one loop seal clears for the 2-inch break, please justify the clearing of the loop seals other than those upstream of the break.

8. The mixture level plot for the 3-inch break also appears very erratic/unstable. Please demonstrate that the solution is converged by demonstrating that reducing the time steps does not decrease the mixture level during uncovery. What is the source of the high frequency oscillations that appear throughout the uncovery period? Please also explain why the two-phase level does not display a gradual increase as opposed to the erratic behavior at 3400 seconds in Fig.5.2.2-16B. The sudden drop in RCS pressure at 3400 seconds suggests that either the solution is not converged or there is erroneous condensation taking place in the RCS. Please explain this behavior.

9. The mixture level plot for the 3-inch break in Fig. 5.2.2-16B displays a steadily decreasing trend after 3400 seconds. Please provide the results of the analysis beyond 5000 seconds to show the level re-covers the top of the core. What is the effect on oxidation for a spot located above the two-phase level at about 21 ft.?

9a. The 4-inch break core mixture level in Fig. 5.2.2-19 shows the top of the core uncovered at 4000 seconds and the clad temperature rising over the last 200 seconds in the temperature plot in Fig. 5.2.2-20. Please present the results beyond 4000 seconds that shows the top of the core is re-covered.

10. Was credit for the hot-leg nozzle gaps and/or alignment key at the barrel flange included in these analyses? If so, please show the effect of not crediting the hot-leg nozzle gap and/or alignment keys on break sizes of 2 to 3 inches.

11. What are the results of small breaks above 4 inches? Please provide analyses of break sizes up to and including 1.0 ft^2 (i.e. 0.2, 0.5, and 1.0 ft^2 cold leg breaks).

12. Please provide a plot of the subcooled level in the core for the 2- and 3-inch breaks.

13. Please also provide a plot of the steaming rate at the two-phase surface for the 2- and 3-inch breaks.

14. What is the two-phase surface void fraction for the 2- and 3-inch limiting breaks versus time?

15. Please provide the nodalization diagram for the NOTRUMP SBLOCA analyses applicable to BVPS-1 and 2.

16. Please explain how the broken loop vapor and liquid break flow rates are computed and where the break is located, relative to the injection nozzle. Is condensation credited in the broken loop injection section? Please explain.

16a. Please provide a plot of the condensation rate in the cell containing the ECCS injection into the discharge leg for each of the breaks analyzed in this submittal.

17. Once the RCS pressure drops below that of the secondary, does the model account for super-heating of the primary steam? How is the interaction between the ECCS injection and super-heated steam modeled in the discharge leg? Inspection of Figs. 5.2.2-7A and B suggest there is no reverse heat transfer modeled in the NOTRUMP Code. Please explain.

18. What are the capacities of the CSTs and atmospheric dump valves for each unit? What is the earliest cooldown time to achieve the shutdown cooling entry temperature and pressure following very small breaks using the secondary dump system?

19. The latest SBLOCA analyses (Reference 3), for BVPS-1 and 2, identify the PCT for SBLOCA as 1894 ^{o}F and 2105 ^{o}F, respectively. Please provide the reference for, or present all of the key transient plots for these analyses. Please also explain why the PCT decreases 350 ^{o}F when EPU conditions are assumed in the analyses. This report also lists many modifications to the SBLOCA models and discusses the results of

sensitivity studies with NOTRUMP, for example, for variations in RCS pressure, auxiliary feedwater (AFW) flow, power distribution, etc. and time steps. Comparisons to SU-T-08 are also discussed. Please provide the results or the references presenting all of the key transient plots for these model changes and sensitivity studies. The plots should include the parameters listed on page 5-13 of Section 5.2.2, entitled "Small Break LOCA."

20. Please identify the reference for the licensing analysis of record for operating at full power conditions prior to the EPU.

21. Are the code modifications and analysis changes described in Reference 3 included in the BVPS-1 and 2 EPU submittal? Please explain. References 2, 3, and 4 of Section 5.2.2 do not appear to include the code changes and modifications listed in Reference 3, in which the PCTs were much higher than those at EPU conditions.

22. Please identify the location of the RCS pressure in the submittal plots.

23. Please identify the hot rod pressure and fuel centerline/fuel average temperatures versus kw/ft for the limiting breaks presented in the submittal.

24. The build-up of boric acid in the core following the 2- and 3-inch breaks can increase appreciably and affect the liquid density in the core region (these breaks display core uncovery beyond 600 seconds). Please estimate the impact of the increased boric acid content on the mixture level, PCT, and oxidation for the limiting small breaks for BVPS-1 and 2.

25. What are the accumulator and refueling water storage tank (RWST) maximum temperatures used in the analyses?

26. To show that the referenced generically approved LOCA analysis methodologies continue to apply specifically to the BVPS-1 and 2 plants, provide a statement that the licensee and its vendor have ongoing processes which assure that the ranges and values of the input parameters for the BVPS-1 and 2 LOCA analysis bound the ranges and values of the as-operated plant parameters. Furthermore, if the BVPS-1 and 2 plant-specific analyses are based on the model and or analyses of any other plant, then justify that the model(s) or analyses apply to BVPS-1 and 2 (e.g. if the other plant design has a different reactor vessel internals design, the model(s) wouldn't apply to BVPS-1 and 2).

27. The LOCA submittals did not address slot breaks at the top and side of the pipe. Please justify why these breaks are not considered for the BVPS-1 and 2 large-break LOCA (LBLOCA) submittals.

28. For BVPS-1 and 2, provide the LBLOCA analysis results tables and graphs to at least 1600 seconds to show that stable and sustained quench is established.

29. It is not clear from LBLOCA and SBLOCA Figures what specific upper core plate is used for BVPS-1 and 2. Please identify the specific upper core plate design used in BVPS-1 and 2.

30. Tables provide LBLOCA and SBLOCA analyses results for the BVPS-1 and 2 EPU. Please provide all results (PCT, maximum local oxidation, and total hydrogen generation), for both LBLOCA and SBLOCA. For maximum local oxidation, include consideration of both pre-existing and post-LOCA oxidation, and cladding outside oxidation and post-rupture inside oxidation. Also include the results for fuel resident from previous cycles.

Section 5.2.3

1. Section 5.2.3, "Hot Leg Switch Over," identifies the mixing volume as the core and upper plenum volume below the bottom elevation of the hot leg. Using the 1971 American Nuclear Society's (ANS's) decay heat standard with a multiplier of 1.2, an average void fraction in the mixing volume of about 65% (corresponding to about 3 hours into the event), and an RWST concentration of 2600 parts per million (ppm) boron, the NRC staff's preliminary calculations show that the precipitation time could be less than 2 hours (this is compared to the 6-hour switchover time identified as conservative for the EPU. The assumption of a collapsed liquid level to the bottom elevation of the hot leg (at all times) is not considered a valid assumption since the loop pressure loss (with the containment at 14.7 psia) will depress the two-phase region and, hence, quench front, well within the core just after and during late reflood. Certainly, for at least 1 to 2 hours after reflood, the mixture level may then only expand into the upper plenum after the decay heat steaming rate has decreased sufficiently. The mixing volume is not fixed at all times, which was identified in Section 5.2.3 of Reference 1, dated April 1975, as the modeling approach. With a 14.7 psia containment pressure, the boric acid buildup during the first hour following reflood of the core is expected to be quite rapid and could produce concentrations in excess of 30 wt% (weight percent) before the mixture expands into the upper plenum.

   In view of these considerations, please review and justify all of the assumptions in the model calculations and re-compute the precipitation time (boron concentration versus time) given there is a steam void in the mixing volume. What is the boric acid concentration versus time when the mixing volume is calculated based on the loop resistance which governs the fluid balance between the downcomer and inner region of the vessel containing the core? The higher boric acid content in the core (liquid density) also needs to be taken into account when computing the time varying mixing volume. The steam generators (SGs) will add heat to the primary steam; this should also be taken into account in computing the loop resistance. It is recommended that only the liquid content in the mixing volume be used to calculate the boric acid concentration and that the void fraction be calculated as a function of time.

2. What is the effect of placing the equivalent of a single-ended cold leg break as a slot on top of the discharge leg? In this situation, the loop seals will refill with ECCS injection, possibly preventing the mixing level from expanding very high into the upper plenum due to the increased resistance. Please compute the boric acid concentration versus time for this case. Please also explain the impact of downcomer boiling on these evaluations.

3. Please provide the core inlet temperature versus time during the injection and recirculation phases of the analyses. What are the containment sump temperature versus time and boric acid concentration versus time for these analyses?

4. At the time of switch to hot and cold leg injection, please show that the boric acid concentration in the upper plenum or core is insufficient to cause precipitation if the minimum injection temperature is used.

5. What is the time to recirculation? What pumped systems are operating to give this RWST drain time and what RWST capacity is assumed in the analyses? What are the minimum and maximum RWST temperatures.

6. Section 5.2.3 is incomplete. Please describe how boric acid precipitation is prevented for all small breaks up to and including those break sizes where simultaneous injection controls boric acid. What guidelines are provided in the emergency operating procedures (EOPs) to assure boric acid does not precipitate for small breaks? Please also describe the methods and inputs to the analysis used to address small breaks.

7. What is the earliest time the switch can be made to simultaneous injection? When would the hot leg steam velocity first drop below the entrainment threshold? At what time during the event would the core decay heat steaming rate be low enough to permit the hot side injection to exceed boil-off sufficiently to flush the core for large breaks?

8. What is the minimum flushing flow to arrest the build-up of boric acid when switch over is determined?

9. What is the bottom elevation of the loop seal pipes (suction legs) and the top elevation of the active core?

10. Please provide the loop friction and geometric pressure loss coefficients, and pressure drops, from the top of the active fuel to the hot legs, SGs, and cold leg piping to the downcomer at the exit of the discharge leg inlet nozzles. Also, please provide the reactor coolant pump (RCP) locked rotor K-factor. Please provide the mass flow rate, hydraulic diameter, flow area, fluid density, and temperature for the key pressure loss components in the loop from the top of the active fuel through the hot legs to the outlet of the discharge leg at steady-state full power conditions. These would include:

    a) top of active fuel to hot leg nozzle
    b) hot leg inlet nozzle
    c) hot leg
    d) SG inlet plenum nozzle
    e) SG inlet plenum
    f) tube sheet inlet
    g) SG tubes
    h) SG u-bend
    i) SG outlet
    j) SG outlet plenum nozzle
    k) suction leg
    l) RCP inlet and outlet

m) discharge leg
n) reactor vessel (RV) inlet nozzle

11. What decay heat multiplier is applied to the 1971 ANS decay heat standard in the evaluations?

12. What is the effect of sump debris on precipitation and mixing throughout the mixing volume? Please explain.

<u>Section 5.3.2</u> <u>Uncontrolled RCCA Bank Withdrawal From a Subcritical Condition</u>

1. Section 5.3.2.5 states, "The results and conclusions of the analysis performed for the uncontrolled RCCA bank withdrawal from a subcritical condition for the NSSS [nuclear steam supply system] power of 2910 MWt bound and support operation at the current NSSS power of 2697 MWt, thus supporting the staged implementation of EPU at Beaver Valley Unit 1 and Beaver Valley Unit 2." Was the analysis performed for the uncontrolled RCCA bank withdrawal from a subcritical condition for BVPS-1, BVPS-2, or both?

2. The sequence of events for this event (Table 5.3.2-1) is identical to the sequence of events for this event in the BVPS-1 UFSAR (Table 14.1-2) and very similar to the sequence of events for this event in the BVPS-2 UFSAR (Table 15.4-1). Was this event re-analyzed for the EPU? If yes, then what EPU-related factors would make a re-analysis necessary?

<u>Section 5.3.3</u> <u>Uncontrolled RCCA Bank Withdrawal at Power</u>

1. Discuss, or cite discussions of, the effect that the EPU would have upon the core limits, protection lines, and overtemperature ΔT trip setpoint calculations used in the BVPS-1 and 2 uncontrolled RCCA bank withdrawal at power event analyses.

2. In Table 5.3.3-1A for BVPS-1, the uncontrolled RCCA bank withdrawal at power analysis assumes a low reactivity insertion rate of 0.4 pcm/sec, and Table 5.3.3-1B for BVPS-2, assumes a low reactivity insertion rate that is five times higher (2.0 pcm/sec) for the same accident. What is the minimum possible reactivity insertion rate for each plant?

3. Figures 5.3.3-7A through 5.3.3-9B indicate that the uncontrolled RCCA bank withdrawal at power analyses meet the Condition II acceptance criterion pertaining to fuel clad damage, due to reactor trips demanded by the overtemperature ΔT and high nuclear flux trip logic. There is little or no information regarding the other two criteria, which pertain to RCS overpressure and escalation of the accident to a more serious event.

    a. RCS overpressure: Show that there is no possibility of RCS overpressurization, assuming that the power-operated relief valves (PORVs) are not available.

    b. Escalation of the accident to a more serious event: Provide analyses results for each plant's minimum possible reactivity insertion rate; assuming various initial power levels and minimum reactivity feedback, to show that the pressurizer would not fill before the reactor is tripped.

Section 5.3.4 RCCA Misalignment

1. Section 5.3.4 states (1), “the effect of a power increase on these generic statepoints has been previously addressed for other Westinghouse designed PWRs,” and (2) “the generic statepoints were evaluated and found to be applicable to the EPU.” Show that generic statepoints apply to BVPS-1 and 2.

2. Describe the plant-specific analyses or evaluations that were conducted for BVPS-1 and 2, which lead to the conclusion that, “Results of the analysis show that a RCCA Misalignment event, with or without a reactor trip, does not adversely affect the core.”

Section 5.3.5 Uncontrolled Boron Dilution

13. For Modes 4, 5, and 6, the BVPS-1 and 2 EPU application indicates an inadvertent boron dilution is “...prevented by administrative controls which isolate the primary grade water system isolation valves from the chemical and volume control system [CVCS], except during planned boron dilution or makeup activities.” What, if any, EPU-related changes have been made to the administrative controls for Modes 4, 5, and 6, which prevent an inadvertent boron dilution.

14. The EPU application indicates that an inadvertent boron dilution in Mode 3 provides the operator with the least amount of time to take action and terminate the event. Please describe the assumptions and analysis that were used to reach this conclusion.

15. The EPU application discussion on the Mode 1 boron dilution, while on automatic rod control states, “The rod insertion limit alarms (low and low-low settings) alert the operator at least 15 minutes prior to criticality.” As the reactor is already critical at this time, please clarify this statement.

16. How much shutdown margin is preserved at the low and low-low settings for the rod insertion limit alarms?

Section 5.3.6 Loss of External Electrical Load and/or Turbine Trip

1. Provide transient curves of SG water level and feedwater flow (normal feedwater and AFW flow) for both BVPS-1 and 2.

Section 5.3.7 Loss of Normal Feedwater

1. Provide a quantitative evaluation to verify the conclusion made in Section 5.3.7.5, that with respect to departure from nucleate boiling (DNB), the loss of normal feedwater event is bounded by the loss of load transient for BVPS-1 and 2.

2. Provide the results of an analysis for the loss of normal feedwater transient concerning peak system pressure using initial conditions and assumptions which will

maximize the peak primary and secondary system pressures (including the assumption of the pressurizer PORVs inoperable)

3. Discuss the provisions made in plant EOPs for controlling AFW at the beginning of the event to prevent excess cooldown during this event.

<u>Section 5.3.8</u> <u>Loss of Non-Emergency AC [alternating current] Power to the Plant Auxiliaries</u>

1. Explain the difference in assumptions made for BVPS-1 and 2, as stated in Section 5.3.8.2.e of the EPU report.

2. Provide a quantitative evaluation to verify the conclusion made in Section 5.3.8.5 of the EPU report that, with respect to DNB, the loss of non-emergency AC power transient is bounded by the loss of flow transient for BVPS-1 and 2.

3. Provide the results of an analysis for the loss of non-emergency AC power transient concerning peak system pressure using initial conditions and assumptions which will maximize the peak primary and secondary system pressures (including the assumption of the pressurizer PORVs inoperable).

<u>Section 5.3.9</u> <u>Excessive Heat Removal Due To Feedwater System Malfunctions</u>

1. In Table 5.3.9-1, which presents the analysis results of the excessive feedwater flow cases, turbine trip is represented as the automatic protection system action which prevents DNB. The associated transient plots indicate that the departure from nucleate boiling ratio (DNBR) is predicted to stabilize at some minimum level that is above the minimum DNBR specified acceptable fuel design limit (SAFDL), consistent with stabilized primary system power and temperature conditions. Actually, the SG high-level turbine trip provides protection against SG overfill, not DNB, and demonstrates that (1) the turbine would not be damaged by excessive moisture carryover, and (2) the event would not develop into a more serious event (e.g., a steamline rupture due to the weight of water in the steam lines). Protection against DNB is provided by the overtemperature ΔT trip in the loss of feedwater heater cases. Therefore, one cannot conclude that, "The decrease in feedwater temperature transient due to the failure of one or more low-pressure heaters is similar to the feedwater flow increase event discussed in detail in this section." Since SG overfill and subsequent escalation of this event into a Condition III or IV event are not mentioned, one cannot conclude that, "The protection features presented in Section 5.3.9.2 provide mitigation of the feedwater system malfunction transient such that the above criteria are satisfied." Please expand Section 5.3.9 to address these differences in the low-temperature and high-flow aspects of the feedwater malfunction cases, and show how timely protection is provided to satisfy all the Condition II acceptance criteria.

2. Include a comparison of the transient response to this event for BVPS-1 for both the original SGs (OSGs) and the RSGs at the EPU conditions.

<u>Section 5.3.10</u> <u>Excessive Load Increase Incident</u>

1. How was it determined that a reactor trip does not occur if an analysis was not performed?

2. How were the statepoints, that were evaluated for DNBR, selected or determined?

3. Please describe the stabilized condition that is reached by the plant, following the initial load increase, and compare that to the results of the load increase analysis in the current licensing basis, which is analyzed at a relatively lower power level.

4. With respect to peak pressure, it is stated that the excessive load increase accident is bounded by the loss of electrical load/turbine trip analysis. Please explain how an event in which steam flow is cut off can bound an event in which steam flow is increased.

Section 5.3.11 Inadvertent Opening of a Pressurizer Relief or Safety Valve

1. Section 5.3.11.5 concludes, "The results of the analysis show that the pressurizer low pressure and overtemperature ΔT trip reactor protection system signals provide adequate protection against the RCS depressurization event since the minimum DNBR remains above the safety analysis limit throughout the transient." The analysis in Section 5.3.11 indicates DNB protection is provided by the low pressurizer pressure trip; but there is no test of the overtemperature ΔT trip. Please provide an analysis of the RCS depressurization event that demonstrates the overtemperature ΔT trip provides adequate protection against DNB.

2. The amendment request states, "An accidental depressurization of the reactor coolant system (RCS) could occur as a result of an inadvertent opening of a pressurizer relief valve. To conservatively bound this scenario, the Westinghouse methodology models the failure of a pressurizer safety valve since a safety valve is sized to relieve approximately twice the steam flowrate of a relief valve and will allow a much more rapid depressurization upon opening." BVPS-1 and 2 are equipped with three PORVs. If all three PORVs were to open, then the resulting relief rate would be about 50% greater than the analyzed safety valve relief flow rate. Verify that there is no single failure in the instrumentation and control system, and there is no operator error that would cause all three PORVs to open.

3. Confirm that an accidental actuation of pressurizer spray would not cause a more rapid depressurization of the RCS than the analyzed case.

Section 5.3.12 Major Rupture of a Main Steam Pipe

1. Section 15.1.5.2 of the BVPS-2 UFSAR states, "Since the steam generators are provided with integral flow restrictors with a 1.4 ft^2 throat area, any rupture with a break area greater than 1.4 ft^2, regardless of location, would have the same effect on the NSSS as the 1.4 ft^2 break." Section 5.3.12.2 of the application states, "For Beaver Valley Unit 2, a 1.069 ft^2 break was analyzed for the Model 51M OSGs since they are designed with a flow restrictor built into the steam exit nozzle." Please explain and document this change in break size, from the UFSAR analysis.

2. Provide the EPU moderator density coefficient curves for BVPS-1 and 2, and compare them to the current licensing basis moderator density coefficient curves.

3. For the DNB analyses, how were the "limiting points in the transient" determined?

4. How was it determined that the case with offsite power available was limiting? If analyses were performed, please describe the key input assumptions and values, and results.

5. Section 5.3.12.4 states, "The analysis demonstrates that this criterion is met by showing that the minimum DNBR does not go below the limit value at any time during the transient." What are the minimum and limiting DNBR values? Please provide transient plots of DNBR for BVPS-1 and 2.

6. Please explain, in physical terms, why the minimum DNBR value is reached 7 seconds before the peak power is reached, for BVPS-1, whereas the minimum DNBR value is reached almost 30 seconds after the peak power is reached, for BVPS-2.

7. Please provide SG mass transient plots for BVPS-1 and 2.

8. Please provide the following transient plots for BVPS-1:

   nuclear power
   pressurizer pressure
   feedwater flow
   core mass flow
   steam flow
   steam generator pressure
   reactor vessel inlet temperature
   reactor vessel average temperature
   core boron concentration
   pressurizer water volume

9. Please provide the following transient plots for BVPS-2:

   reactor coolant system pressure
   integrated SI flow

10. Please explain why the maximum core heat flux is about the same for both units, despite the fact that the break size for BVPS-1 is more than 30% larger than the break size for BVPS-2.

11. Please explain why the maximum core heat flux in BVPS-1 is reached about 156 seconds after the maximum core heat flux in BVPS-2 is reached, despite the fact that the break size for BVPS-1 is more than 30% larger than the break size for BVPS-2.

12. Tables 5.3.12-1A and 5.3.12-1B provide the sequence of events for the main steamline break (MSLB) event. These tables list the timing when secondary pressure reaches the low steam pressure safety injection setpoint (SIS) (BVPS-1 - 460 psia, BVPS-2 - 338

psia). Subsequent engineered safety features actuations system (ESFAS) actuations occur 8, 27, and 30 seconds after the SIS actuation signal. The sequence of events does not appear to include any delay time between the time the setpoint is reached to the time that the actuation signal is generated. Please describe where these delays are addressed.

13. During an MSLB, the depressurization of the faulted SG may promote an increase in main feedwater delivery. Describe the model of the feedwater flow into the faulted SG. Include a plot illustrating main and AFW flow (lbm/sec) throughout the event.

14. The UFSAR provides significantly more information on the selection of initial conditions, input parameters, and analysis assumptions. Please update the application MSLB analyses to include this level of detail or indicate where differences between the UFSAR analyses and this submittal exist. Include a discussion of potential single active failures.

15. Demonstrate that the credited reactor protection system (RPS) trip functions and supporting instrumentation and cables are qualified for a harsh containment environment. Further, quantify the environmental instrument uncertainties and analytical setpoints.

16. Demonstrate that fuel clad failure does not occur as a result of high local power density during the return-to-power near the vicinity of the stuck RCCA. Quantify the local peaking factors in the area under the stuck RCCA.

17. The VANTAGE 5H and RFA fuel assemblies employ different critical heat flux (CHF) correlations and a different DNBR limit. Further, the location of the mid-span mixing vanes introduces an axial-dependency to the CHF correlation.

    (a) The local conditions experienced during an MSLB may be outside the applicability of the WRB-1 and WRB-2M CHF correlations. Please describe the use of these correlations during the MSLB event. If the W-3 correlation is being employed, demonstrate its applicability to both the VANTAGE 5H and RFA fuel assemblies at these MSLB local conditions.

    (b) Quantify the most severe shift axial power distribution (AXPD) during a cooldown event and how the core thermal-hydraulic models account for this shift. Include in this discussion the calculation of DNBR with an axial-dependent CHF correlation.

18. Figure 5.3.12-3B depicts SG pressure during the MSLB event. The trend in faulted SG pressure does not appear to support reaching the 338 psia SIS setpoint at 1.0 seconds. Please discuss.

19. Initial SG liquid mass inventory has an impact on the results of the return-to-power MSLB event. Tables 5.3.1-4A/B list initial condition uncertainties on indicated SG water level. Describe the application of these uncertainties to the initial indicated level and how plant operations (i.e. technical specifications) ensure that the inventory assumed in the analysis is maintained.

<u>Section 5.3.14</u> <u>Complete Loss of Forced Reactor Coolant Flow</u>

1. Provide the results of an analysis of the loss-of-flow transient concerning peak system pressure using initial conditions and assumptions which will maximize the peak primary and secondary system pressures (including the assumption of the pressurizer PORVs inoperable).

Section 5.3.15 Single Reactor Coolant Pump Locked Rotor

1. Explain the differences in the assumptions for BVPS-1 and 2.

2. Provide the DNB transient curves for BVPS-1 and 2.

3. How many fuel pins were calculated to be subject to a DNBR that is below the safety limit of 1.55? Compare and discuss this to the number of failed fuel pins that are assumed for calculation of radiological consequences (20%).

4. Describe the limiting single failures assumed in the locked rotor accident for the DNB case and for the peak pressure case.

5. Confirm that the acceptance criteria listed in Section 5.3.15.4 of the EPU report are consistent with the current licensing bases of BVPS-1 and 2.

6. Confirm that a concurrent loss-of-offsite power (LOOP) is assumed in the analysis for a locked rotor accident.

Section 5.3.16 Rupture of a Control Rod Drive Mechanism [CRDM] Housing/Rod Cluster Control Assembly Ejection

1. Verify that the peak reactor coolant pressure could not cause RCS stresses to exceed the faulted-condition stress limits (i.e., BVPS-1 and 2, under EPU conditions, continue to be addressed in the generic evaluation of Reference 4).

Section 5.3.17 Major Rupture of a Main Feedwater Pipe

1. Demonstrate that the credited RPS trip functions and supporting instrumentation and cables are qualified for a harsh containment environment. Further, quantify the environmental instrument uncertainties and analytical setpoints.

2. To illustrate the break spectrum cases investigated, provide a plot of break size versus peak RCS pressure and break size versus peak pressurizer liquid level.

3. Section 5.3.17.2 of the EPU report states that "PORVs are assumed to be operable."

a. Describe the safety function and mitigating actions performed by the PORVs during the postulated feedwater line break (FWLB) event.

b. Describe the operability requirements for the PORVs.

c. Repeat the UFSAR, Section 15.2.8.2.1, PSV operability analyses at the EPU conditions for both BVPS-1 and 2. Include a description of inputs and assumptions and identify the limiting FWLB case with respect to PSV operability for each unit.

4. To account for instrument uncertainties, a reactor trip on low-low SG level is credited in the FWLB event at an analytical setpoint of 0% nuclear rated steam. Discuss the modeling uncertainty of LOFTRAN to predict indicated SG liquid level (in both faulted and intact SGs) under the dynamic conditions experienced during a FWLB event for both the Model 54F and 51M SG designs.

5. Provide a plot of indicated SG liquid level for all three SGs for a range of break sizes to demonstrate that a low-low water level signal (required to start motor-driven AFW pumps) is achieved in two SGs.

6. Justify the timing of the LOOP for BVPS-1 and 2. For clarity, separately identify trip setpoint reached, reactor trip breakers opening, CRDM holding coil decay, and LOOP on the sequence of events table.

7. Provide plots of feedline break flow rate (lbm/sec) and enthalpy and AFW flow rate (lbm/sec) into each SG.

8. UFSAR, Section 15.2.8.2 states, "A 60-second delay was assumed following the low-low level signal to allow time for start-up of the emergency diesel generators and the auxiliary feedwater pumps". Table 5.3.17-1A has AFW delivery starting 60 seconds following the low steamline pressure setpoint being reached and 57 seconds following the low-low SG water level. Please discuss the AFW pump start time and delivery (lbm/sec) for both BVPS-1 and 2. For clarity, separately identify trip setpoint(s) reached (including low-low for each SG), reactor trip breakers opening, CRDM holding coil decay, LOOP, emergency diesel generator start, load sequencing, AFW pump start, and AFW delivery on the sequence of events table.

<u>Section 5.3.18</u> <u>Spurious Operation of the Safety Injection (SI) System at Power</u>

1. Section 5.3.18 and Tables 5.3.20-3A and 5.3.20-3B indicate that the pressurizer is predicted to fill; but there are no corresponding plots at the end of Section 5.3.18. Please provide plots depicting the plant transient conditions following a spurious SI at-power event, for both BVPS-1 and 2. In particular, please provide transient plots of pressurizer water level (or volume), encompassing the time at which the pressurizer becomes water-solid.

2. In the EPU report, Note 8.8 of the table entitled, “Information in Response to the NRC’s Review Standard for Extended Power Uprates - RS-001, Revision 0", states that, “For the inadvertent operation of emergency core cooling system and chemical and volume

control system malfunctions that increase reactor coolant inventory events: (a) non-safety-grade power-operated relief valves should not be credited for event mitigation and, (b) pressurizer level should not be allowed to reach a pressurizer water-solid condition."

How do the BVPS-1 and 2 spurious SI at-power event analyses meet the requirements specified in this Note?

3. The pressurizer PORVs might open, during the spurious SI at-power event, when the pressurizer is water-solid. Are they expected to reseat properly? If yes, state how they, and their associated discharge piping, have been qualified for water relief during a spurious SI at power event. Also, please verify that the automatic control circuitry of these valves meets Class 1E requirements.

4. If the pressurizer PORVs don't open during the spurious SI at-power event, then the PSVs might open when the pressurizer is water-solid. Describe and document the PSV operability analyses that indicate these valves can be expected to reseat properly.

5. How was the current licensing basis for the spurious SI at-power event established (e.g., by 10 CFR 50.59 evaluation or by NRC staff review and approval)? If by 10 CFR 50.59 evaluation, then please provide a copy of the 10 CFR 50.59 evaluation. If by NRC staff review and approval, then please cite the applicable license amendment.

6. Please supply the ECCS flow delivery rate, as a function of RCS pressure, that was assumed for the spurious SI at-power event analyses. Compare this flow delivery rate to that assumed in the current licensing basis analyses of BVPS-1 and 2.

7. Analyze or evaluate the CVCS malfunction that does not change the RCS boron concentration. Show that this event will not fill the pressurizer before the operator can shut off the charging flow.

<u>Section 5.3.19</u> <u>Steam System Piping Failure at Full Power</u>

1. Demonstrate that the credited RPS trip functions and supporting instrumentation and cables are qualified for a harsh containment environment. Further, quantify the environmental instrument uncertainties and analytical setpoints.
2. The VANTAGE 5H and RFA fuel assemblies employ different CHF correlations and are subject to different DNBR limits. Further, the location of the mid-span mixing vanes introduces an axial-dependency to the CHF correlation.

   (a) The local conditions experienced during an MSLB may be outside the applicability of the WRB-1 and WRB-2M CHF correlations. Please describe the use of these correlations during the MSLB event. If the W-3 correlation is being employed, demonstrate its applicability to both the VANTAGE 5H and RFA fuel assemblies at these MSLB local conditions.

   (b) Quantify the most severe shift axial power distribution (AXPD) during a cooldown event and how the core thermal-hydraulic models account for this shift. Include in this discussion the calculation of DNBR with an axial-dependent CHF correlation.

3. Section 5.3.19.3(b) states that uncertainties on power, temperature, pressure, flow, etc. are being applied to the limiting statepoints in the W-3 DNBR calculations. Please quantify this application of uncertainties. Note that if the application of uncertainties to the initial conditions impacts the timing of the reactor trip or point of minimum DNBR, then this application may be non-conservative. Please discuss.

4. Demonstrate that the credited ΔT reactor trip functions have accounted for instrumentation (e.g. resistance temperature detector (RTD)) delay/lag times and asymmetric loop temperatures in a conservative manner. If applicable, demonstrate that the effects of excore temperature shadowing have been included in all reactor trip functions.

5. Does the 2.0-second delay time for the overpower ΔT reactor trip function include the CRDM holding decay time?

6. To illustrate the break spectrum cases investigated, provide a single plot of break size versus reactor trip time (including applicable delays) for all of the credited reactor trip functions.

7. Demonstrate that an HFP MSLB case including a single failure and/or LOOP would be less limiting than the cases presented in Section 5.3.19.

<u>Section 5.4</u> <u>Steam Generator Tube Rupture</u>

1. In the EPU report for BVPS-1, the SG tube rupture (SGTR) accident analysis is based on the assumption that the leak flow from the RCS to the secondary side of the SG is terminated 30 minutes following the event initiation. The resulting break flow mass transfer is then used to calculate the radiological consequences of the SGTR. Inherent in this evaluation is the assumption that the operator can terminate the break flow in 30 minutes. Plants with similar designs to BVPS-1 have reported to the NRC that, in simulator exercises, the operators demonstrated that the time to terminate the break flow exceeded the 30-minute assumption. The longer period of time needed to isolate the SG with the tube rupture could lead to an increase in radiological releases from that which was assumed when the SG was isolated within 30 minutes of event initiation. Either verify that the 30-minute operator action assumption is valid for BVPS-1and 2, or provide the results of a re-analysis for an SGTR accident with conservative assumptions including a most limiting single failure, a coincident LOOP, and operator actions according to plant EOPs. These re-analyses of SGTRs should address both offsite dose and SG overfill issues.

2. Discuss the limiting single failure assumed in the case concerning SG overfill. Compare the assumed single failure with: 1) failure of an atmospheric dump valve (ADV) in the intact SG which causes slower RCS cooldown and increased cumulative leak flow from the RCS to the SGs, and 2) failure of AFW flow control which causes a more severe SG overfill transient.

3. Discuss the limiting single failure assumed in the case concerning offsite dose. Compare the assumed single failure with a stuck open ADV in the failed SG after it is automatically opened following the event.

4. Confirm that a concurrent LOOP is assumed in the SGTR analysis.

5. Confirm that the operator actions assumed in the SGTR analysis are consistent with the BVPS-1 and 2 EOPs.

6. Describe EOP steps that would provide early control of AFW flow in feeding the ruptured SG to prevent SG overfill.

Section 5.8 Anticipated Transients Without SCRAM (ATWS)

1. Provide the results of analyses and/or evaluations performed for the loss-of-load ATWS at BVPS-1 and 2, assuming the EPU power level, and an MTC of -5.5 pcm/ EF. If from analyses, provide transient plots and sequence of events tables denoting the time and value of peak RCS pressure. If from evaluations, describe the methods and values that were used.

2. Verify that the maximum differential pressure, across the tubesheet and tubes of the Model 54F RSG, matches or exceeds the value listed in Appendix C of WCAP-8330 (Reference 5).

Section 6.1 Thermal-Hydraulic Design

1. Define the limits of "high flow" and "low flow", as used in Table 6.1-1.

2. Review of the thermal-hydraulic design in Section 6.1 led to the thermal-hydraulic parameters of the SGs in Section 4.7. Why is Section 4.7.1, "Beaver Valley Unit 1 Replacement Steam Generators," omitted from the proprietary version of WCAP-16307? (It is included in the non-proprietary version.)

Section 6.2 Nuclear Design

1. The evaluation provided in the BVPS-1 and 2 EPU report is based on an EPU RTP equilibrium condition. However, transition conditions may be more limiting. Conditions in which feed assemblies have excess reactivity, in anticipation of the EPU, may be more limiting. The first or second cycle at the EPU RTP may be more limiting, especially if the once and twice burned assemblies were not manufactured with increased reactivity. How does the licensee intend to manage the transition from the current BVPS-1 and 2 RTP of 2689 MWt to the EPU RTP of 2900 MWt? Please confirm the limiting condition and it's acceptability.

17. In Table 6.2-1, "Key Safety Parameters," the most positive MTC is indicated to be +2 pcm/ EF. The current licensing basis for BVPS-1 and 2 is for the MTC to be less

positive than +2 pcm/ EF for power levels up to 70% of RTP, with a linear ramp to 0.0 pcm/ EF at 100% of RTP. Please verify that the MTC listed in Table 6.2-1 continues to be less positive than +2 pcm/ EF for power levels up to 70% of RTP, and ramps to 0.0 pcm/ EF at 100% of RTP.

18. Table 6.2-1 indicates only the reactor core power and core average linear heat rate are being affected by the EPU. Please confirm the impact of the EPU on other key safety parameters not listed in Table 6.2-1. Please include transition conditions.

19. Please confirm the licensee’s commitment, in Section 6.2.3, to maintain the key safety parameters listed in Table 6.2-1 within the bounds listed in Table 6.2-1 through the use of fuel management techniques. Please include transition conditions.

20. Section 6.2.3.2 states, “Because the core and vessel average temperatures are being maintained approximately at the current levels, the other components that contribute to the calculation of the shutdown margin, like the moderator temperature defect and the rod worths, should not be affected by the EPU in any systematic way.” Factors other than temperature may affect shutdown margin, moderator temperature defect, and rod worth. The fuel management techniques required to maintain the key safety parameters listed in Table 6.2-1 will require changes to those factors, e.g. enrichment, integral fuel burnable absorber loading, and critical boron concentration. Please provide an evaluation of the synergistic effects of all the changes on shutdown margin, power defect, moderator temperature defect, rod worth, and other reactivity contributors. Please include transition conditions.

Section 9.4 Emergency Core Cooling System

1. Section 9.4.1 of the EPU report indicated that the charging/SI pumps are being modified to improve the ECCS performance and flow rates to support the EPU. Provide the details of these pump modifications, and the tests performed for the modified ECCS pumps.

REFERENCES:

1. Pearce, L. W., FirstEnergy Nuclear Operating Company (FENOC), Letter to NRC, “Beaver Valley Power Station, Unit No. 1 and 2, License Amendment Request Nos. 302 and 173,” October 4, 2004.

2. NRC Review Standard RS-001, Revision 0, "Review Standard for Extended Power Uprates," December 2003.

3. Pearce, L. W., FENOC, Letter to NRC, “10 CFR 50.46 Report of Changes or Errors in ECCS Evaluation Models,” November 19, 2004.

4. Risher, D. H., Westinghouse, “An Evaluation of the Rod Ejection Accident in Westinghouse Pressurized Water Reactors using Special Kinetics Methods,” WCAP-7588; Rev. 1A, January 1975.

5. Westinghouse, WCAP-8330, “Westinghouse Anticipated Transients Without Trip Analysis,” August 1974.

6. Richardson, J. E., NRC, Letter to Herrmann, T.E., Westinghouse Owners Group, “Acceptance for Referencing of Licensing Topical Report WCAP-12910, ‘Pressurizer Safety Valve Set Pressure Shift,” February 19, 1993.

Beaver Valley Power Station, Unit Nos. 1 and 2

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