FENOC

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L-05-078

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555-0001

Subject: Beaver Valley Power Station, Unit Nos. 1 and 2
BV-1 Docket No. 50-334, License No. DPR-66
BV-2 Docket No. 50-412, License No. NPF-73
Responses to a Request for Additional Information in Support of License Amendment Request Nos. 302 and 173

By letter dated March 11, 2005, the U.S. Nuclear Regulatory Commission (NRC) issued a request for additional information (RAI) relative to FirstEnergy Nuclear Operating Company (FENOC) license amendment requests 302 and 173 (Reference 1). These license amendment requests propose increasing the licensed power level approximately 8 percent above the current licensed power level.

Enclosure 1 contains the FENOC responses to the March 11, 2005 RAI. Enclosure 2 contains the Westinghouse proprietary and nonproprietary response to RAI questions N.2 and N.4 and the associated affidavit. Included in Enclosure 2 is Westinghouse authorization letter CAW-05-1999 with accompanying affidavit, Proprietary Information Notice, and Copyright Notice. In addition to the accompanying affidavit, Proprietary Information Notice, and Copyright Notice, Enclosure 2 contains the following item.

1. Responses to NRC RAI N.2, "BVPS Reactor Vessel Internals Calculated Stress Values for Flow Induced Vibration" (Proprietary) and NRC RAI N.4, "BVPS Reactor Coolant Pump Component Maximum Upset Stress Intensities" (Proprietary)

As Item 1 of Enclosure 2 contains information proprietary to Westinghouse Electric Company LLC, it is supported by an affidavit signed by Westinghouse, the owner of the information. The affidavit sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b) (4) of Section 2.390 of the Commission's regulations.

Accordingly, it is respectfully requested that the information which is proprietary to Westinghouse be withheld from public disclosure in accordance with 10 CFR Section 2.390 of the Commission's regulations.

AP01

Correspondence with respect to the copyright or proprietary aspects of the items listed above or the supporting Westinghouse affidavit should reference CAW-05-1999 and should be addressed to J. A. Gresham, Manager, Regulatory Compliance and Plant Licensing, Westinghouse Electric Company LLC, P.O. Box 355, Pittsburgh, Pennsylvania 15230-0355.

Reference 2 transmitted FENOC license amendment request 320. This license amendment request is known as the replacement steam generator (RSG) LAR. The RSG LAR contains the Technical Specification changes proposed in Reference 1, the Extended Power Uprate (EPU) LAR, that are needed to replace the BVPS Unit No. 1 steam generators and to credit the safety analyses at 2900 MWt. Since approval of the RSG LAR is expected well before approval of the EPU LAR, an effort has been made to identify which question in Enclosure 1 also applies to the RSG LAR. To aid the EPU and RSG LAR reviewers, the LAR applicability for each question is noted in Enclosure 1. Enclosure 3 contains a list of the questions contained in Enclosure 1 and their LAR applicability.

The responses contained in this transmittal have no impact on the proposed Technical Specification changes, or the no significant hazards consideration, transmitted by Reference 1.

No new regulatory commitments are contained in this submittal. If you have questions or require additional information, please contact Mr. Henry L. Hegrat, Supervisor - Licensing, at 330-315-6944.

I declare under penalty of perjury that the foregoing is true and correct. Executed on May 26, 2005.

Sincerely,

L. W. Pearce

L. William Pearce

Enclosures:
1 Responses to RAI dated March 11, 2005
2 Proprietary and nonproprietary responses to RAI questions N.2 ad N.4
3 March 11, 2005 RAI Question LAR Applicability

References:
1. FENOC Letter L-04-125, License Amendment Requests 302 and 173, dated October 4, 2004.
2. FENOC Letter L-05-069, License Amendment Request 320, dated April 13, 2005.

c: Mr. T. G. Colburn, NRR Senior Project Manager
Mr. P. C. Cataldo, NRC Sr. Resident Inspector
Mr. S. J. Collins, NRC Region I Administrator
Mr. D. A. Allard, Director BRP/DEP
Mr. L. E. Ryan (BRP/DEP)

L-05-078 Enclosure 1

Response to Request for Additional Information (RAI)
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, Agencywide Documents Access and Management System (ADAMS) Accession No. ML042920300, FirstEnergy Nuclear Operating Company (FENOC, the licensee) proposed changes to BVPS-1 and 2 operating licenses to increase the maximum authorized power level from 2689 to 2900 megawatts thermal (MWt) (approximately 8%). The proposed amendment would also change the BVPS-1 and 2 Technical Specifications (TSs) to authorize operation with replacement Model 54F steam generators (SGs) for BVPS-1 and authorize full implementation of an alternate source term (AST) for both BVPS-1 and 2, and deletion of the power range, neutron flux high negative rate trip for both BVPS-1 and 2. Various other miscellaneous and administrative TS changes were also proposed not related to the EPU. The Nuclear Regulatory Commission (NRC) staff has determined that it will need the additional information identified below to complete its review.

A. Section 5.12, "Fire Protection Safe Shutdown (Appendix R)," and Section 9.24, "Additional Systems Reviewed"

A.1 Question: (Applicable to EPU)

In "Review Standard for Extended Power Uprates (RS-001)," Rev. 0, Attachment 1 to Matrix 5, "Supplemental Fire Protection Review Criteria, Plant Systems" states that "... power uprates typically result in increases in decay heat generation following plant trips. These increases in decay heat usually do not affect the elements of a fire protection program related to (1) administrative controls, (2) fire suppression and detection systems, (3) fire barriers, (4) fire protection responsibilities of plant personnel, and (5) procedures and resources necessary for the repair of systems required to achieve and maintain cold shutdown. In addition, an increase in decay heat will usually not result in an increase in the potential for a radiological release resulting from a fire. However, the licensee's application should confirm that these elements are not impacted by the extended power uprate..."

The NRC staff notes that Section 5.12 of Attachment 2 to the BVPS-1 and 2, EPU application does not address the items above. Please address each of these items.

Response:

Operation at the proposed power uprate conditions will not affect the aspects of the fire protection program relative to administrative controls, the design or operation of the plants fire detection and fire suppression systems, the fire barrier assemblies installed to satisfy NRC requirements, or the fire protection responsibilities of plant personnel. In addition, the potential for a radiological release resulting from a fire will not increase due to operation at extended power uprate (EPU) conditions.

Procedures and resources necessary for the operation and repair of systems required to achieve and maintain cold shutdown are also not changed due to EPU. The impact of EPU on plant post-fire safe shutdown procedures is addressed in the response to question A.2 below.

No significant changes in combustible loading are anticipated due to the planned modifications associated with EPU. Changes to the plant configuration or combustible loading as a result of the modifications necessary to implement the EPU will be evaluated under the plants existing NRC approved fire protection plan. No new equipment is credited for post-fire safe shutdown, nor does it re-route essential cables or relocate essential components credited for post-fire safe shutdown. Compliance with the fire protection program will not be affected because the power uprate evaluation did not identify changes to design or operating conditions that will adversely impact the post-fire safe shutdown capability.

A.2 Question: **(Applicable to EPU)**

In RS-001, Attachment 1 to Matrix 5, "Supplemental Fire Protection Review Criteria, Plant Systems" states that "...where licensees rely on less than full capability systems for fire events..., the licensee should provide specific analyses for fire events that demonstrate that (1) fuel integrity is maintained by demonstrating that the fuel design limits are not exceeded, and (2) there are no adverse consequences on the reactor pressure vessel integrity or the attached piping. Plants that rely on alternative/dedicated or backup shutdown capability for post-fire safe shutdown should analyze the impact of the power uprate on the alternative/dedicated or backup shutdown capability...The licensee should identify the impact of the extended power uprate on the plant's post-fire safe-shutdown procedures."

The NRC staff notes that Section 5.12, "Fire Protection Safe Shutdown (Appendix R)," of Attachment 2 to the BVPS-1 and 2, EPU application does not address either of the items above. Please address each of these items.

Response:

BVPS does not rely on less than full capability systems for fire events. BVPS Unit 1 and 2 meet the post-fire safe shutdown requirements of 10 CFR 50 Appendix R (applicable to BVPS Unit 1) and BTP CMEB 9.5-1 (applicable to BVPS Unit 2). Alternative shutdown capability is provided for protection or separation of systems or equipment required for post-fire safe shutdown and the current fire protection licensing basis is described in UFSAR Section 9.10 (Unit 1) and UFSAR Section 9.5A (Unit 2).

The analyses and evaluations for postulated fire events performed for BVPS-1 and BVPS-2 at EPU conditions demonstrate that the (1) fuel integrity is maintained by demonstrating that the fuel design limits are not exceeded, and (2) there are no adverse consequences on the reactor pressure vessel integrity or the attached piping for BVPS-1 and BVPS-2.

For BVPS-1, the safe shutdown evaluation described in Section 5.12 concluded that the impact of EPU on fire protection safe shutdown is acceptable. An analysis for cold shutdown capability was performed for a scenario that includes a limiting "worst case" fire that envelops the auxiliary feedwater pump (AFW) pump room fire and credits only the minimum set of equipment expected to be available for recovery. The analytical simulation showed that for EPU conditions, the reactor coolant system (RCS) can be safely shut down and cooled down to cold shutdown conditions within the NRC approved cold shutdown time requirement of 127 hours (Ref. NRC safety evaluation report (SER) for BVPS-1 dated March 14, 1983). During the fire protection safe shutdown and cooldown, acceptable values were maintained for important parameters (e.g., pressurizer level was maintained on span, RCS subcooling was maintained greater than uncertainties, RCS/steam generator temperatures and pressures were maintained within acceptable ranges close to no-load values during hot standby and they decreased to appropriate values at cold shutdown).

For BVPS-2, the safe shutdown evaluation described in Section 5.12 was performed and concluded that there are no plant modifications proposed for implementation of EPU that will impact the shutdown scenarios. The decay heat increases with EPU conditions; however the total time required to reach cold shutdown remains within the 72 hour acceptance criteria for cold shutdown identified in standard review plan (SRP) 9.5.1 and applicable to BVPS-2.

A review was performed of BVPS-1 and BVPS-2 procedures and associated time-critical manual actions credited for post-fire safe shutdown and the supporting analyses to determine the impact of the power uprate conditions. Based on a review of the actions required and the supporting analyses, the following was concluded:

- The uprated power condition will not affect the plants ability to meet the performance goals of 10CFR50, Appendix R, Section III.L (applicable to BVPS-1) and the branch technical position (BTP) CMEB 9.5-1, Section C.5.c (applicable to BVPS-2), for either normal or alternate shutdown fire areas.
- The uprated power condition will not result in any changes to the credited safe shutdown methodology.
- Manual operator actions credited for post-fire safe shutdown will remain feasible for the uprated power condition.

B. Steam Generator Tube Integrity

B.1 Question: (Applicable to EPU)

Laser-welded sleeves were discussed for BVPS-2 in Section 4.7.2.4.6 (p. 4-95) of the "Beaver Valley Power Station Extended Power Uprate Licensing Report September 2004" (EPU Licensing Report). Please confirm that the laser welded sleeves will still meet all applicable regulatory criteria, consistent with the original design/licensing basis of the sleeves, under EPU conditions.

Response:

It is confirmed that the laser welded sleeves (LWS) meet all applicable regulatory criteria, consistent with the original design/licensing basis of the sleeves, for application in the BVPS-2 steam generators at EPU conditions. The acceptability of LWS in the BVPS-2 steam generators for EPU conditions is documented in Revision 2 to WCAP-13484, "Beaver Valley Units 1 and 2 Westinghouse Series 51 Steam Generator Sleeving Report - Laser Welded Sleeves," October 2002. Proprietary and non-proprietary versions of this report were submitted as Enclosure 5 to the EPU License Amendment Request (L-04-125, October 4, 2004).

There are no LWS currently installed in the BVPS-2 steam generators.

B.2 Question: (Applicable to EPU)

Section 4.7.2.6 (p. 4-103) of the EPU Licensing Report discusses the tube plugging or repair limit for BVPS-2. The licensee concludes that the analyses and evaluations for the tube plugging or repair limit for the higher power level (2900 MWt) bound and support operation at the current power level. Discuss whether the Regulatory Guide (RG) 1.121 analysis has shown that the 40% through-wall plugging limit is adequate for EPU conditions.

Response:

Section 4.7.2.6 describes the Regulatory Guide (RG) 1.121 analysis that was performed to define the tube "structural limits" for EPU conditions. As described in this section, the allowable tube plugging or repair limit is obtained by incorporating into the resulting structural limit a growth allowance for continued operation until the next scheduled inspection and also an allowance for eddy current measurement uncertainty.

The technical specification (4.4.5.4.a.6.a) tube plugging or repair limit of 40% through-wall (TW) by non-destructive examination (NDE) with appropriate allowances for growth and eddy current measurement uncertainty supports the structural limits defined in Section 4.7.2.6 for EPU conditions.

B.3 Question: (Applicable to EPU)

FENOC letter, L-04-115 (September 1, 2004, ADAMS Accession No. ML042520356), stated that two tubes in SG C, BVPS-2, were plugged and stabilized due to a loose part. The part had caused degradation to one of the tubes and could not be removed. Since loose parts may affect tube integrity, please discuss the results of your analysis to confirm that the parts in your SG will not compromise tube integrity for the period of time between inspections under the EPU conditions.

Response:

The change in secondary side flow rates due to EPU is judged negligible with regard to loose part impact upon SG tube integrity. The recent cases of loose part wear at BVPS-2 have established actual depths bounded by 40% TW, with most cases involving a precursor signal at the previous inspection(s). As the recent observed wear rates remain acceptable with regard to impact to SG tube leakage integrity, the minimal depth and length of these indications suggests large margins against the performance criteria. Additionally, FENOC performs sludge lancing and Foreign Object Search and Retrieval (FOSAR) at each BVPS-2 outage.

B.4 Question: (Applicable to EPU)

The SG U-bend fatigue analysis for BVPS-2 (p. 4-87) showed that up to six tubes could require removal from service by plugging if the normal operating steam pressure falls below a certain value. The report states that tubes will be removed from service using sentinel plugs only or have cable tube dampers installed with plugging. What are the criteria that determine which preventive action will be used? Once a need for preventive action is identified, when will that action be taken?

Response:

Either method, sentinel plugging or plugging with stabilization is an acceptable repair practice. There are no criteria that result in selection of one process over another. Preventive action is required prior to the plant operating at the higher power level. Preventive action will be taken no later than the 2R12 refueling outage planned for the fall of 2006. This action is in the Corrective Action Program and was identified previously as a commitment (Reference LAR 302/173 Enclosure D, Commitment #8).

C. Alternative Source Term

C.1 Question: (Applicable to RSG & EPU)

Two of the issues affecting the release of radioactive iodine are:

- **ability to maintain sump pH greater than 7 for 30 days following a loss-of-coolant accident (LOCA), and**
- **backleakage to the refueling water storage tank**

Do the previous evaluations of these issues, which were reviewed by the staff for selective AST implementation (ADAMS Accession No. ML032530204, 9/10/03), apply to both the EPU and containment conversion conditions? If not, please provide evaluations that do apply.

Response:

Yes, the analyses and evaluations supporting the previous selective alternative source term (AST) implementation, approved by the NRC in Amendments 257/139 on 9/10/03, included conditions, inputs and assumptions applicable to both containment conversion (CC) and EPU (with BVPS-1 replacement steam generators (RSG)).

D. Chemical and Volume Control System (Including Boron Recovery System)

D.1 Question: (Applicable to EPU)

The EPU Licensing Report (p. 9-14 and 9-15) states that letdown line pressure will not have a significant impact on letdown flowrates and N–16 delay time. The report also states that the N-16 dose rate will increase due to the EPU and be managed through plant access restrictions and exposure monitoring. If this approach to managing N–16 dose rate has been reviewed and accepted by the NRC staff, please provide a reference.

Response:

The discussion in Section 9.2.3.3 of the EPU Licensing Report refers to the existing site Radiation Protection Program which controls access to radiation areas and ensures individual worker exposure remains within acceptable limits. No radiation increases will be exceeded or even approach NRC limits or the site administrative limits. Existing plant programs will provide sufficient defense-in-depth capability such that essential radiation protection to plant workers will continue to be provided. Procedural controls and as low as reasonably achievable (ALARA) techniques are used to limit doses in areas having increased radiation levels. These controls and techniques are described in each unit's updated final safety analysis report (UFSAR). See UFSAR Sections 11.5.2 (Unit 1) and 12.5.3.5 (Unit 2), Dose Control, and Unit 2 UFSAR Section 12.5.3.1.1, Physical and Administrative Controls. Therefore, the Radiation Protection Program will continue to fully comply with 10 CFR 20 requirements, and the N-16 dose rate increase will not impact that ability. No specific additional review by NRC was/is required or performed.

E. Steam Generator Blowdown System (SGBS)

E.1 <u>Question</u>: (Applicable to EPU)

The application states that blowdown required to control secondary chemistry and SG solids will not be impacted by the EPU (p. 3-8 and 3-10 of the EPU Licensing Report.) What are the blowdown flow (lbm/hr) and velocity at present operating conditions and at EPU conditions for each unit? Compare these to the design values to demonstrate that EPU conditions are within design values.

Response:

The blowdown flow rates required to control chemistry and buildup of solids in the steam generators for BVPS-1 and BVPS-2 are related to allowable condenser in-leakage, total dissolved solids in the plant service water, and allowable primary-to secondary leakage. Since these variables are not changed by power uprate, the blowdown mass flowrate required for control of secondary chemistry and steam generator solids is not impacted by power uprate.

The BVPS-1 blowdown system is designed to accommodate a blowdown flowrate of up to 200 gpm (77,000 lbs. / hr.) per steam generator. The BVPS –2 blowdown system is designed to accommodate blowdown flow rates in the range of 5 gpm (1925 lbs/hr) to 100 gpm (38,500 lbs./hr.) per steam generator. At current power conditions the maximum operating blowdown flow rate for BVPS-1 and BVPS-2 is 100 gpm (38,500 lb/hr) and 97 gpm (37,000 lb/hr), respectively, per steam generator. This will not change under EPU conditions.

Also, the BVPS-1 Replacement Steam Generators (RSGs) are designed to allow for a maximum continuous full power blowdown flow of 1% of feedwater flow (44,000 lb/hr per steam generator) at EPU conditions. Higher blowdown flow rates of up to a maximum of 3% of feedwater flow at full power conditions are acceptable for short period. Therefore, the RSG is designed with a continuous blowdown capacity (44,000 lbs. / hr.) that envelopes the maximum blowdown flow of 38,500 lbs. / hr at which the system will be operated.

Under EPU conditions, the SG secondary side operating pressure will change given that there will be a change in feedwater and main steam mass flow rates. This will likely require blowdown system control valve adjustments. The control valve capacity was evaluated for the anticipated range in SG operating pressure and the control valve has adequate range. The maximum continuous blowdown flow velocity in any SGBS system piping for the required blowdown flow rates (including the 200 gpm design flow for BVPS-1) is less than 10 ft/sec.

E.2 Question: (Applicable to EPU)

The application states that the operating position of the flow control valves will be impacted (p. 3-8 and 3-10 of the EPU Licensing Report). Please discuss the amount and significance of this change.

Response:

BVPS-1 and BVPS-2 blowdown flow control valves have a primary range and "blast" (i.e., extended) range capacity in excess of the required EPU blowdown flow rates at pressure drops based on minimum full-load steam generator steam pressure corresponding to EPU conditions. The acceptable minimum steam generator pressures has been lowered for EPU, which may require a repositioning of the blowdown flow control valves of approximately 10 to 15%. While reduction in pressure will reduce the maximum achievable blowdown mass flow rates, the capacity of the valves at the minimum operating pressures will be adequate for the EPU conditions described in the response to question E.1.

E.3 Question: (Applicable to EPU)

Does the licensee's evaluation of the impact of EPU on the SGBS apply to the Unit 1 replacement SGs?

Response:

Yes, the information presented in Section 3.1.4.5 regarding the impact of EPU on the SGBS applies to both BVPS-1 with replacement SGs and BVPS-2 with original SGs.

The BVPS-1 RSGs are being designed for EPU conditions (970 MWt/RSG), including a maximum continuous blowdown flow rate of 1% of feedwater flow at full power EPU conditions, which corresponds to approximately 44,000 lb/hr. Higher blowdown rates of up to a maximum of 3% of feedwater flow at full power EPU conditions are acceptable for short periods.

E.4 Question: (Applicable to EPU)

Has the blowdown system experienced degradation due to flow accelerated corrosion? Did the blowdown system evaluation consider a potential increase in flow accelerated corrosion due to higher secondary system flow rates (including particulates) under EPU conditions?

Response:

Inspections performed as part of the flow accelerated corrosion (FAC) program have found no evidence of SGBS system degradation in either BVPS-1 or BVPS-2. The system mass flow rate is not expected to increase due to the EPU conditions or the BVPS-1 replacement SG. The blowdown flow velocity in the SGBS system piping will remain below the threshold for anticipating FAC, reference response to question E.1. No increase in particulate introduction to the SGs is expected even though the feedwater flow will increase with EPU. The system will continue to be monitored for degradation by the FAC program.

F. Protective Coating Systems

Section 10.14 of the EPU Licensing Report states that the protective coatings inside the BVPS-1 and 2 containments comply with the design-basis accident (DBA) testing requirements of American National Standards Institute (ANSI) N101.2, and that these existing coatings are acceptable and compatible with the environments associated with EPU conditions. In order to perform the necessary evaluation of the coating systems in containment, the NRC staff requests that the licensee provide the following additional information:

F.1 Question: (Applicable to EPU)

Section 10.14 of the licensing report (p. 10-12) states that the higher radiation levels corresponding to EPU conditions will be bounded by the normal plus DBA tested values. It also states that the other DBA conditions are "not expected to change significantly as a result of EPU." Will all qualification parameters (temperature, pressure, chemical environment, radiation level) for Service Level 1 coatings be bounded at EPU conditions by the normal plus DBA tested values?

Response:

All environmental conditions of EPU operation at BVPS Unit Nos. 1 and 2 (i.e., normal and LOCA) will be bounded by the coating system testing.

For EPU operation, environmental conditions of accident peak temperature for LOCA, total integrated dose and sump boron concentration increase. The accident peak pressure and humidity do not change relative to the original design conditions. The LOCA peak temperature for EPU operation is 267.8°F for BVPS-1, and is 270.1°F for BVPS-2. The sump pH will be from 7.0 to 10.5 for both BVPS-1 and BVPS-2. The EPU total integrated dose (TID) for BVPS-1 is 2.54E8 Rads inside the crane wall (it is less outside) and for BVPS-2 the TID is 2.37E8 Rads inside the crane wall. Normal operating conditions remain unchanged other than the operating pressure that will be increased on both units to bring it to near atmospheric pressure for operational reasons (refer to license amendment request (LAR) 317/190 for containment conversion). Following EPU and Containment Conversion, containment spray boron concentrations will range from 2160 ppm to 2600 ppm including consideration of accumulation of boron in the core and the maximum RWST allowable boron concentration.

The coatings used for BVPS-1 were purchased to Specification BVS 493. This specification required the paint to be in accordance with the requirements of ANSI N101.2, "Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities." The specification also required the paint to be in accordance with the quality assurance requirements in ANSI N101.5.7. The specification identified coating systems for steel and concrete with demonstrated ability to withstand the harsh DBA conditions of temperature, chemical sprays and radiation. The conditions that were specified in ANSI N101.2 were 280°F pressurized water reactor (PWR) DBA temperature peak, a boron concentration range of 2000 to 4000 ppm boron, and 1E8 – 2E9 Rads.

Since the ANSI N101.2 specifies peak DBA temperature greater than the initial and EPU peak LOCA temperatures, all coatings continue to be acceptable with respect to the peak LOCA temperature as well as with respect to the peak pressure and the DBA humidity. The chemical spray boron concentration continues to be bounded by the original coating qualification specified in ANSI N101.2. The coatings also continue to be acceptable with respect to the normal environmental conditions of temperature, pressure and humidity. The radiation qualification level for coatings systems used at BVPS-1 is at least1E9 Rads.

The coatings used for BVPS-2 were purchased to Specification 2BVS 950. This specification required the paint to be in accordance with the requirements of Reg. Guide 1.54, which endorses ANSI N 101.2, "Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities." The specification also required the paint to be in accordance with the quality assurance requirements in ANSI N101.4. The specification identified coating systems for steel and concrete.

As is the case for the BVPS-1 coatings, the EPU environmental conditions for the peak LOCA temperature, humidity and chemical spray for BVPS-2 are within the tested conditions and the coatings continue to be acceptable. The radiation test conditions for the BVPS-2 coatings are at least 1E9 Rads.

F.2 Question: (Applicable to EPU)

Describe the actions that will be taken if the qualification of Service Level 1 coatings are not bounded by the EPU/DBA conditions, since coating failure could threaten performance of the emergency core cooling system (ECCS) sump after a LOCA.

Response:

There are no cases where the Service Level 1coatings used at BVPS are known to be unable to withstand the EPU environmental conditions. The qualification of Service Level 1 coatings bound the EPU/DBA conditions as indicated in the response to F.1.

Potential coating failures are identified by plant personnel during refueling operations and other in-containment surveillances, and are entered into and evaluated by the site Corrective Action Program. Repairs to degraded coatings are made with fully qualified coatings.

F.3 Question: (Applicable to EPU)

The Updated Final Safety Analysis Reports (UFSARs) state that the DBA simulation tests were "for the most part" (BVPS-1, page 5.2-51) or "in general" (BVPS-2, page 6.1-5) consistent with ANSI N101.2. Please discuss any lack of consistency with N101.2 in the qualification of Service Level 1 coatings used in containment.

Response:

No specific deviations from the ANSI N101.2 requirements are identified. However, Section 5.2.7.2, page 5.2-51, of the BVPS-1 UFSAR states "of the proposed ANSI 101.2" indicating the N101.2 standard was a proposed document at the time the BVPS-1 final safety analysis report (FSAR) was written. The "for the most part" language in the BVPS-1 UFSAR therefore may reflect the uncertainty of the final N101.2 standard requirements. The BVPS coating specifications required the vendors to meet the requirements of the referenced documents (ANSI N101.2 and Regulatory Guide 1.54 are referenced documents for BVPS-1 and BVPS-2 respectively). The specifications took no exceptions to either N101.2 or RG 1.54. The materials were required to be supplied with certifications of conformance. Documentation shows the qualification testing exceeded the plant operation and accident conditions.

Therefore, there is no lack of consistency with N101.2 in the qualification of Service Level 1 coatings used in containment at BVPS Unit 1 or Unit 2.

F.4 Question: (Applicable to EPU)

Has any major coatings' work been performed inside containment since the original application? If so, was it done using a qualified coating bounded by EPU conditions?

Response:

There has been no major coating work (painting work or recoating) performed inside either BVPS-1 or BVPS-2 containment structures since the original application. Minor maintenance has been performed inside to the containment interior structure such as painting of coatings that have been damaged or abraded. Major components have been coated as necessary during overhauls. Also modification work has required painting of new material and areas where paint was removed for welding etc. The painting that was done was performed with qualified coatings, or evaluated for acceptance for certain vendor supplied equipment. As indicated in the response to question F.1, Service Level 1 coating qualification requirements bound EPU conditions.

G. Effect of EPU on Flow-Accelerated Corrosion (FAC)

In Section 10.4 (p. 10-4) of the EPU Licensing Report, the licensee discusses the FAC program. The licensee also states that the EPU increases the operating pressure, temperature, and velocity in several systems, and that these changes have been used to update the FAC program. In order to evaluate the licensee's FAC program, the NRC staff requests that the licensee provide the following additional information:

G.1 Question: (Applicable to EPU)

Provide the name of the predictive code used to evaluate FAC at BVPS-1 and BVPS-2. Briefly describe how the code is applied.

Response:

The BVPS FAC program uses EPRI's Checworks Integrated Software for Flow Accelerated Corrosion. Checworks is primarily used as a data management program to evaluate and store thickness data. Checworks is also used to analytically model piping systems having consistent, predictable local operating conditions. These systems include Condensate, Extraction Steam, Feedwater, Feedwater Heater Drains, Moisture Separator Reheater Drains, and Steam Generator Blowdown. The primary objective of these models is to identify the most susceptible components to allow optimization of the examination scope. However, actual examination data, data trending and operating experience are the foundation of the BVPS FAC program. The most reliable wear rate determinations have been point-to-point comparisons of measurements obtained on the same component at different outages. The results of actual examination data are input to the models to improve the wear rate predictions.

G.2 Question: (Applicable to EPU)

Describe the criteria used in the FAC program for (1) selecting piping segments for inspection, (2) selecting points at which to make thickness measurements, (3) determining the frequency of thickness measurements, (4) selecting thickness measurement methods, and (5) making replacement/repair decisions.

Response:

(1) BVPS FAC program includes all susceptible high-energy carbon steel piping segments, including both single phase and two-phase segments. A formal susceptibility study has been performed that identifies piping within the scope of the program and includes explanations for all excluded piping. Piping containing nominal Chromium content equal to or greater than 1-1/4%, single phase systems with a temperature below 200°F, and piping with no flow or which is in use less than 2% of plant operating time are excluded from the program scope in accordance with EPRI NSAC202L-R2.

(2) Examination locations are selected based on the following considerations: Results from previous BVPS examinations (trending), industry events, operating experience, Checworks predictive analysis, system engineering and operations requests based on valve leakage, non-typical plant operations, etc., and inspection coverage for model calibration.

(3) The examination frequency of previously examined locations is based on the estimated time to reach the minimum thickness requirement. The minimum measured thickness and the estimated wear rate are used to determine the estimated time. The Checworks methodology is used to determine the total lifetime wear used for the wear rate determination. Where actual wear has been confirmed, examinations are performed at least one outage prior to the estimated time when the minimum required thickness will be exceeded. The minimum wall thickness screening criteria for each location is based on the higher required thickness resulting from either the stresses due to internal pressure (hoop stress) or stress due to mechanical loading. The hoop stress check is commonly called the Code Min-Wall equation. The mechanical loading check is based on the pipe stress analysis for the piping associated with the inspection location. The maximum stress values from anywhere within the analytical boundaries are used in determining the pipe wall required for mechanical loading and include longitudinal pressure, deadload, seismic and occasional load cases if applicable.

(4) The primary thickness measurement method at BVPS is ultrasonic examination because of its accuracy and repeatability. Pulsed eddy current has been used as a screening method for Feedwater Heater shells.

(5) If examinations find the component thickness below the minimum required thickness or estimates indicate that the thickness will exceed the minimum required thickness before the next scheduled refueling outage, repairs or replacements would be made prior to plant startup and the actions entered and tracked via the BVPS Corrective Action Program.

G.3 <u>Question</u>: (Applicable to EPU)

Please describe any significant changes in FAC rates anticipated as a result of EPU conditions.

Response:

Significant changes in FAC wear rates are not expected as a result of EPU conditions. In response to Question G.4 (below), a description is provided of expected wear rate changes associated with the EPU conditions.

G.4 <u>Question</u>: (Applicable to EPU)

For each of the five components considered most susceptible to FAC before the EPU and after the EPU, discuss the change to the velocity, temperature, pressure, and predicted corrosion rate resulting from the change to EPU conditions.

Response:

The five components considered most susceptible to FAC at BVPS are located in the 1st Point and 2nd Point Extraction Steam Systems at both BVPS-1 and BVPS-2. Evaluations, based on the Checworks predictive model, have been performed to determine the impact of the uprate on each of these subsystems. Fluid velocity and temperatures will increase, to varying degrees, as a result of the power uprate. Refer to Tables 1 and 2 for the pre and post uprate values for the most susceptible components in the 1st and 2nd Point Extraction steam lines.

The evaluation concluded that the wear rates would decrease in each of these subsystems under uprate conditions. In three of the four subsystems, the increase in temperature drives the decrease in wear rates. Based on the Checworks algorithm, for the range of temperatures in the 1st and 2nd Point Extraction Steam subsystems, a temperature increase contributes to a wear rate decrease. In the fourth case, the improved steam quality is the governing factor. The average wear rate decrease for components in these four subsystems was approximately 17%. At BVPS, predictive modeling is just one criterion for selecting examination locations. Despite the results of this evaluation, the 1st and 2nd Point Extraction Steam components will continue to receive frequent examinations.

Other systems were also evaluated where the velocity changes were considered significant. It was found that the largest wear rate increase is expected in the 4th Point Heater Drains piping toward the Feedwater Heater inlet nozzles. Refer to Tables 3 and 4 for a representative example of the pre and post uprate values for the 4th Point Heater Drain components with increase in wear rates. The average wear rate increase for these components is approximately 24%. Previous examination data exist on components in this portion of the system. No evidence of significant wear has been found to date. Post uprate examinations in this system will be input into the analytical models to validate the wear predictions and improve the accuracy of the models.

Table 1 – 1st & 2nd Point Extraction Steam Line (BVPS Unit 1)

Component ID	Pre-Uprate				Uprate			
	Temp F	Velocity ft/sec	Quality	Wear Rate (mils/year)	Temp F	Velocity ft/sec	Quality	Wear Rate (mils/year)
1-S2E-01-01N	390.0	39.884	0.904	11.614	394.1	42.790	0.900	11.574
1-S2E-02-01N	390.0	41.326	0.904	11.837	394.1	44.332	0.900	11.797
1-S2E-03-02T(D/S)	390.0	43.626	0.904	12.913	394.1	46.834	0.900	12.862
1-S2E-03-05T(D/S)	387.2	46.192	0.907	12.746	390.9	49.733	0.904	12.465
1-S2E-03-08T(BR.)	387.2	42.372	0.907	13.403	390.9	45.595	0.904	13.112

Table 2 – 1st & 2nd Point Extraction Steam Line (BVPS Unit 2)

Component ID	Pre-Uprate				Uprate			
	Temp F	Velocity ft/sec	Quality	Wear Rate (mils/year)	Temp F	Velocity ft/sec	Quality	Wear Rate (mils/year)
2ES-20-06N	396.9	39.467	0.902	16.541	388.7	46.002	0.904	11.338
2ES-21-01N	396.9	39.508	0.902	16.550	388.7	46.047	0.904	11.345
2ES-22-05T(U/S)	396.9	41.689	0.902	18.054	388.7	48.661	0.904	12.367
2ES-26-15T(U/S)	396.9	41.689	0.902	21.194	388.7	48.798	0.904	14.539
2ES-26-17T(D/S)	388.4	84.498	0.904	24.812	388.7	44.440	0.904	12.162

Table 3 - 4th Point Heater Drain Line (BVPS Unit 1)

Component ID	Pre-Uprate				Uprate			
	Temp F	Velocity ft/sec	Quality	Wear Rate (mils/year)	Temp F	Velocity ft/sec	Quality	Wear Rate (mils/year)
1-W4D-01-14E	237.2	5.017	0.000	1.620	235.4	14.037	0.004	1.820

Table 4 - 4th Point Heater Drain Line (BVPS Unit 2)

Component ID	Pre-Uprate				Uprate			
	Tem pF	Velocity ft/sec	Quality	Wear Rate (mils/year)	Temp F	Velocity ft/sec	Quality	Wear Rate (mils/year)
2HDL-006-54-3EP	228.7	34.934	0.008	2.377	228.9	45.307	0.009	2.622

H. Electrical Systems

H.1 Question: (Applicable to EPU)

Section 9.17.1 of the EPU Licensing Report: The licensee stated that the Iso-phase Bus rating of 28,000 amperes (forced air-cooled) is adequate. However, the bus could see a current of 29,557 amperes under EPU conditions with 95% of rated voltage ((1070 x 1000)/(1.7321 x 22 x 0.95)). Please explain.

Response:

Evaluation of the isolated phase bus for adequacy at EPU conditions was based on a comparison between the maximum anticipated full-load current and the bus design ratings. The maximum full-load current was determined based on existing system and component limitations, summarized as follows.

The current nameplate rating of the main unit generator of each unit is 1,026 MVA (based on 75 psig hydrogen), 22 kV, 0.90 power factor, three-phase, 60 Hz, 1800 RPM. Upgrade of each main generator output to 1,070 MVA at 0.92 power factor will occur as a part of the EPU project.

Evaluation of each main generator was based on a comparison between the applicable generator parameters (i.e., generator reactive capability curve) and the minimum (i.e., 99.1% of rated voltage for BVPS-1, 99.9% of rated voltage for BVPS-2) and maximum (i.e., 101.4% for BVPS-1, 102.6% for BVPS-2) operating voltage constraints when each machine operates at EPU conditions. Unit operation at leading and lagging power factor was considered.

Unit Operation at Lagging Power Factor Load

Station load flow (voltage profile) analyses were reviewed to identify gross generator output when each unit operates at normal full-load conditions. Review of the calculated results indicates that the minimum station bus voltage requirements permit main generator operation at a lagging power factor only. Gross generator output at maximum normal full-load conditions for each unit, as determined in the applicable load flow analysis, is tabulated below.

Additional analyses were performed to determine the maximum reactive capability of each machine at lagging power factor assuming:

- Each main generator operating at the maximum output voltage level identified in the applicable station load flow analysis.
- Each unit operating at normal full-load conditions.
- The 345 kV switchyard at minimum design voltage (0.985 pu, or 339.8 kV).

The results of the analysis are tabulated below.

Unit Operation at Leading Power Factor:

None of the scenarios evaluated in the station load flow analyses result in main unit generator operation at leading power factor. Additionally, review of the generator reactive capability curve confirmed that the machines have limited capability when importing reactive power at EPU conditions. However, additional analyses were performed to determine the maximum reactive capability of each machine at leading power factor assuming:

- Each main generator operating at the minimum output voltage level identified in the applicable station load flow analysis.
- Each unit operating at normal full-load conditions
- The 345 kV switchyard at maximum design voltage (1.03 pu, or 355.4 kV).

The results of the analysis are tabulated in Table 5.

Table 5						
	Generator Output					
Unit	MW	MVAR	MVA	Volt, kV	PF, % (1)	IPB Main Bus Current, Amps (2,3)
Generator Operation at Lagging Power Factor						
1	984	281	1,024	21.802	96.1	27,117
2	977	304	1,023	21.978	95.5	26,874
Generator Operation at Maximum Lagging Power Factor						
1	984	375	1053	22.308	93.4	27,253
2	977	375	1046	22.572	93.4	26,755
Generator Operation at Maximum Leading Power Factor						
1	984	0	984	21.802	1.0	26,058
2	977	0	977	21.670	1.0	26,030

Notes:

1. Power Factor (PF), % = (MW / MVA) x 100
2. IPB Main Bus Current, amps = (MVA x1000) / (KV x 1.7321)
3. IPB Main Bus rating is 28,000 amps, continuous

As indicated in Table 5, the maximum possible isolated phase bus current, based on the generator and switchyard voltage constraints, was determined to be less than the bus rating. Therefore the design of the isolated phase bus is adequate at EPU conditions.

H.2 Question: (Applicable to EPU)

Section 9.17.3: The licensee stated that the load flow analysis shows that the BVPS-1 unit station service transformer (USST), 1C, is slightly overloaded on the Y winding.

A. Please provide the calculated load on the Y winding.

B. Please provide the impact of the overload on the Y winding on the following:
1) the load terminal voltages
2) the winding temperatures
3) the transformer life
4) the bus duct (Y winding to switchgear) rating

Response:

A. The calculated worst-case loading on the Y winding of USST 1C is 18.49 MVA. The normal load for the Y winding fed through 4KVS-1A bus is 4KVS-1AE bus, 480VUS-1-8N bus, 480VUS-1-1A bus, and 480VUS-1-3E bus. For conservatism in the analysis, the 480VUS-1B and 480VUS-1-3F bus loads were added to USST 1C "Y" winding as possible non-1E cross tie bus loads, which are normally supplied from USST 1D. These additional loads represent an abnormal bounding condition that would only occur if supply breakers to 480VUS-1B and 480VUS-1-3F bus trip. It should also be noted that the analysis was performed using all connected loads at 4KV and 480V unit substations without applying diversity, although the MCC loads were calculated utilizing diversity factors. As a result of these conservatisms, the analysis shows "Y" winding is loaded beyond the normal rating of the winding.

The maximum pre-EPU measured load at the 4KVS-1A bus is 13.75 MW. The EPU load increase for "Y" winding is 0.223 MW. The additional non-1E cross tie bus (480VUS-1B and 480VUS-1-3F) maximum measured load is 0.65 MW. Therefore, in normal operational alignments the "Y" winding load will be always below 15 MW, which is below the normal rating of the "Y" winding.

B. The following information is provided:

1) Load flow analysis of the postulated worst-case load scenario concluded that downstream bus and equipment terminal voltage levels were acceptable when the load on the Y winding of USST 1C is 18.49 MVA, and therefore there is no impact on the load terminal voltages.

2) As stated in response to question H.2.A, the actual "Y" winding loading will be less than rating of the "Y" winding. Therefore, the temperature of the "Y" winding will be within the design limit of the transformer. The temperature rise on the transformer at the full load (35.8 MVA) is 65°C. The total conservatively analyzed loading on the transformer (for X and Y winding) is less than 35.8 MVA. Therefore, the transformer winding temperature will be below design temperature.

3) The system model used to determine USST loading is conservative and considered to be a bounding case. The "Y" winding supplies power to 4160 V Bus 1A, which, in turn, supplies power to several downstream 480 V double-ended unit substations (load centers). During normal plant operation, two load centers (480VUS-1-1A & 480VUS-1-3E) are aligned to Bus 4KVS-1A. The system model used to analyze the postulated scenario models Bus 4KVS-1A supplying power to two additional 480 V substation busses (480VUS-1-1B & 480VUS-1-3F) due to a cross-tie between the buses of two of the downstream double-ended load centers. The cross-tied buses are normally supplied from 4160 V Bus 4KVS-1C, which is supplied from USST 1D. As stated in H.2.A the loads on the transformers USST 1D or SSST 1A will be within the rating of the windings during EPU conditions. It is similarly reasonable to conclude that transformer life is not adversely affected by the postulated loading for the reasons identified in (2), above. Additionally, the postulated load represents an off-normal bus alignment. During normal plant operation, winding loads would be below the applicable nameplate ratings. Consequently, if an automatic cross-tie of 480V load center busses event would occur, the load addition to the transformer "Y" winding will remain within the design limit of the winding.

4) Non segregated cable bus connects the "Y" winding of USST 1C to 4KVS-1A. The bus duct is rated at 3000 amps continuous. The calculated loading on the bus is 2575 amps. Therefore, the bus is adequately sized.

H.3 <u>Question</u>: (Applicable to EPU)

Section 9.17.4: The licensee stated that the load flow analysis shows that BVPS-1 system station service transformer (SSST) 1A is slightly overloaded on the Y winding.

A. Please provide the calculated load on the Y winding.

B. Please provide the impact of the overload on the Y winding on the following:
1) the load terminal voltages
2) the winding temperatures
3) the transformer life
4) the bus duct (Y winding to switchgear) rating

Response:

A. The calculated worst-case loading on the Y winding of SSST 1A is 18.48 MVA. However, as stated in response to question H.2.A, the maximum loading on the "Y" winding of the USST 1C transformer is less than15 MW. When load is transferred to the SSST 1A from the USST 1C, a loading of less than 15 MW will be applied to the SSST "Y" winding, which is below the rating of SSST 1A "Y" winding. When the SSST supplies DBA loads, the large motors (e.g. main feed water pumps) are unloaded so the cumulative remaining loads will be less then 15 MW on SSST 1A "Y" winding.

B. The following information is provided:

1) The conservative load flow analysis of the postulated worst-case load scenario concluded that downstream bus and equipment terminal voltage levels were acceptable when the load on the "Y" winding of SSST 1A is 18.48 MVA. If power is supplied by the SSST 1A transformer, while the generator is in operation, as stated in H.2.B, the maximum load would be within the rating of the "Y" winding. As stated above, the calculated voltage at load, even using 18.48 MVA is still above required voltage, or degraded grid relay setting voltage.

2) As stated in H.3.B 1, the actual "Y" winding loading for SSST 1A will be less than the rating of the "Y" winding. Therefore, the temperature of the "Y" winding will be within the design limit of the transformer. Additionally, the system model used to determine SSST 1A loading is conservative and considered to be a bounding case. The "Y" winding supplies power to 4160 V Bus 1A,which, in turn, supplies power to several downstream 480 V double-ended unit substations (load centers). During normal plant operation, only a single bus of each load center is aligned to 480V Bus 1A. The system model used to analyze the postulated scenario models 480V Bus 1A supplying power to two additional 480 V buses due to a cross- tie between the buses of two of the downstream double-ended load centers. The cross-tied buses are normally supplied from 4160 V Bus 1C, which is supplied from SSST 1B. As stated in H.2.A, the loads on the transformers USST 1D or SSST 1A will be within the rating of the windings during EPU conditions.

3) It is similarly reasonable to conclude that transformer life is not adversely affected by the postulated loading for the reasons identified in (2), above. Additionally, the postulated load represents an off-normal bus alignment. During normal plant operation, winding loads would be below the applicable nameplate ratings.. It should also be noted that station loads during normal plant operation are usually supplied from the USST. Consequently, the SSST may not carry load for significant periods of time

4) Non-segregated cable bus connects the "Y" winding of SSST 1A to 4160 V Bus 1A. The bus duct is rated 3000 amps, continuous. Calculated load on the bus, as determined in the applicable load flow analysis, is 2525 amps.

H.4 Question: (Applicable to EPU)

Section 9.18.2

A. **The licensee stated that there is an increased load on the charging pump motors. Provide the increased load and how it impacts the voltages and the operation (such as loading, voltage regulation, spare capacity) of the emergency diesel generators (EDGs).**

B. **Address the impact of increased motor loads (reactor coolant pump motor, condensate pump motor, charging pump motor) on the degraded voltage relay setpoints.**

C. **Evaluate the impact of these increased loads on the life of the motors mentioned above.**

Response:

A. BVPS-1

The EDG loading analysis identifies the charging pump loading for loss of offsite power (LOOP), safety injection (SI) and containment isolation phase B (CIB) accident conditions The charging pumps have already been modified for EPU. The existing pre-EPU maximum loading was identified as 696.87 BHP (554.2 KW) during SI and CIB accident conditions and bounds EPU conditions. In this condition the motor will be operating beyond its service factor. For LOOP accident condition the calculated brake horsepower (BHP) increased from 517 BHP (411.2KW) to 584.9 BHP (465.2 KW). The BVPS-1 EDG loading analysis evaluated the changes for the EPU and concluded that the maximum coincident load is within the allowable limits for all operating conditions (DBA, LOOP, SI and station blackout (SBO)). Available margin, dependent on the particular operating scenario, varies between DBA (29 KW) and LOOP (109 KW). The minimum margin of 29 KW for a DBA will last for one to two hours. After the Quench Spray Pump is shutdown, the margin will be 176 KW. The total EDG loads for DBA, LOOP, and SI do not exceed the UFSAR limit of 2745 KW for these events. The SBO loading does not exceed the EDG 2000-hour rating of 2850 KW, which is the SBO limit. Additionally it was determined that sufficient voltage exists at the equipment, when supplied from the EDG, and voltage regulation is not impacted.

BVPS-2

The EDG loading analysis identifies the charging pump loading for LOOP, SI and CIB accident conditions. The EPU maximum loading was identified as 695.1 BHP (552.8 KW) during SI and CIB accident conditions. The existing pre EPU maximum loading was identified as 670 BHP (532.9 KW) during SI and CIB accident conditions. In this condition the motor will be operating in to the range of its service factor. For LOOP accident condition the calculated BHP increased from 526 BHP (418.3 KW) to 584.9 BHP (465.2 KW). The EDG loading analysis has evaluated the BHP changes for EPU and concluded that the maximum coincident load is within the allowable limits for all operating conditions (DBA, SI, LOOP and SBO). Available margin, dependent on the particular operating scenario, varies between 129 KW (SBO) – 1421 KW (SI). The total EDG loads for DBA, LOOP, SI and SBO do not exceed the UFSAR design limit of 4535 KW. Additionally it was determined that sufficient voltage exists at the equipment.

B. The electrical distribution system was evaluated with respect to load changes due to EPU. The electrical analyses demonstrated that adequate voltages are available at the electrical loads after accounting for the load changes due to EPU. The electrical analyses determined that adequate voltage was available with no change to degraded voltage relay settings. Therefore, the existing degraded voltage relay settings remain acceptable for EPU operation.

C. Operation at EPU conditions will not adversely affect the expected life of motors that continue to operate within their nameplate rating. Motor loads at EPU conditions will exceed the nameplate rating of the BVPS-1 Reactor Coolant Pump and BVPS-1 Condensate Pump motor drives. Similarly, motor loads will exceed the nameplate rating of the Charging Pump motor drives installed in each unit, but only during accident conditions. These motors were evaluated and found acceptable for impact to component life due to operation at loads exceeding nameplate rating as summarized below:

1) The reactor coolant pump (RCP) motors were evaluated to demonstrate that they could operate acceptably at the conditions associated with EPU. Previous evaluations have shown acceptable RCP motor operation beyond its rating (6000 BHP) at the original reactor power level and 1.4% power uprate. The BVPS-1 RCP hot-loop motor loading at 22% SGTP (6335 BHP) exceeds the nameplate rating by 5.6%. Analysis indicates the hot-loop stator temperature rise will be approximately 46.3°C at the EPU motor load, which is below the motor design temperature limit. Therefore, there is no additional degradation of the motor life due to EPU operation.

2) The life of the charging pump motor was evaluated for the increased loading. The actual operating characteristic of the charging pumps during normal, abnormal, and accident (worst-case DBA) conditions were evaluated. It was concluded that the charging pump motors are qualified for the full 40 year license life of BVPS and will not require replacement, given expected modes of operation, including a post accident operation period of 183 days and operational environments that include conservative IEEE-323 and hot spot margins.

3) The BVPS-1 Condensate Pump motors are rated 3000 HP. Each motor will operate at 3170 BHP at uprate conditions. Since the motors were supplied with a 1.15 Service Factor (motor rating of 3450 HP at Service Factor load), each motor has inherent operating margin. That is, the motors are capable of operating at a somewhat higher than nameplate (but below service factor) load without incurring loss of service life. The BVPS-2 Condensate Pump motors operate below nameplate rating.

H.5 Question: (Applicable to EPU)

Section 9.18.3: Evaluate the impact of the increase in loads on the life of the cables.

Response:

Existing feeder cables for all medium voltage motors affected by EPU were evaluated to confirm that each is adequately sized (ampacity) to support plant operation at EPU conditions. The evaluation concluded that the derated cable ampacity (i.e., cable ampacity after accounting for all applicable derating factors) exceeded the required load current during normal plant full load operation. Accordingly, life of the existing feeders is not adversely affected by EPU. The results of the evaluation are tabulated in Table 6.

Table 6

BVPS Unit	Equipment	Equipment ID	Load Current at EPU (AMPS)	Derated Cable Ampacity (AMPS)
1	Condensate Pump	CN-P-1A, 1B	411	442.8
1	Heater Drain Pump	SD-P-1A, 1B	219	280.44
1	Reactor Coolant Pump	RC-P-1A, 1B, 1C	875	879.04
1	Sec Component Cooling Pump	CC-P-3A, 3B	65	173.02
1	Feedwater Pump	FW-P-1A1, 1A2	407	560.88
1	Feedwater Pump	FW-P-1B1, 1B2	407	560.88
1	Charging Pump	CH-P-1A, 1C	92	138.42
1	Charging Pump	CH-P-1B	92	120.27
2	Condensate Pump	2CNM-P21A, B, C	416	455.92
2	Heater Drain Pump	2HDH-P21A, B	97	146.94
2	Reactor Coolant Pump	2RCS*P21A, B, C	797	966.96
2	Separator Drain Pump	2HDH-P22A, B	39	146.94
2	Sec Component Cooling Pump	2CCS-P21A, B	78	146.94
2	Feedwater Pump	2FWS-P21A1, A2	416	560.88
2	Feedwater Pump	2FWS-P21B1, B2	416	560.88
2	Charging Pump	2CHS*P21A, B, C	92	132.25

The evaluation also noted that during plant startup, assuming RCS cold loop conditions, maximum steam generator tube plugging and minimum allowable motor terminal voltage, the ampacity of the existing RCP motor feeder cables was slightly exceeded. However, the evaluation concluded that the condition was acceptable because it occurs only during startup, is of limited duration (i.e. as RCS temperature increases, motor load current decreases) and motor terminal voltage will be substantially higher than the minimum required during startup because plant operators are required to raise bus voltage to approximately 105 % (4160 V base) prior to motor start. Additionally, the feeders have inherent design margin because they can operate at 130°C for up to 500 hours during their operating life without loss of life. The evaluation determined that cable temperatures during maximum cold loop current would be approximately 100°C.

H.6 Question: (Applicable to EPU)

Sections 9.18.4 and 9.18.5

A. **The licensee stated that "EDG loading is not affected by the load increase...." Provide a detailed explanation of why the load increases on the 4160V and 480V motors does not affect the EDG loading.**

B. **The BVPS-1, UFSAR, Section 8.5.2, states that the EDG loads do not exceed 2745 kW. Please confirm that the EDG load does not exceed 2745 kW during EPU condition.**

C. **If the load has increased above 2745 kW, provide the effect of operation at EPU conditions on maintenance and on the EDG support systems (such as fuel storage and transfer systems).**

Response:

A. The question refers to the load increase experienced by the 460 V containment air recirculation (CAR) fan motors of each unit described in EPU Licensing Report Section 9.18.4. As stated in the referenced section, the CAR fans are not automatically loaded on the EDGs for any postulated loading scenario. Consequently, EDG loading is not impacted by the CAR fan load increase. The EDG steady state loading calculations were revised to incorporate load increases experienced by the only motors affected by uprate and capable of being supplied from the EDGs (i.e., 4160 V Charging Pump motors and the 460 V Control Rod Drive Mechanism Shroud fan motors of each unit). The analysis confirmed that each EDG has adequate capacity to support unit operation at uprate. The response to question H.4.A provides details of the EDG margin for BVPS-1 and BVPS-2.

B. The BVPS-1 diesel generator loading calculation incorporated the changes associated with EPU conditions and the total EDG loading does not exceed 2745 kW for DBA, LOOP, or SI operating scenarios. Refer to the response to question H.4.A for more information including acceptability of the loading for SBO conditions.

C. As indicated in the responses to questions H.4.A and H.6.B, the BVPS-1 EDG load does not exceed 2745 kW except during an SBO, which is non-limiting relative to diesel fuel supply since fuel oil supply is based on full load for seven days and new load does not exceed full load rating of the EDG (Ref. LR Section 9.18.5).

H.7 Question: (Applicable to EPU)

Section 9.19.1

A. **Provide the service factor of containment air recirculation (CAR) motors and the impact on the motor life if the service factor is 1.0 at EPU conditions.**

B. **Has operation of the CAR motors been reviewed and accepted by the motor manufacturer at EPU conditions?**

C. **Provide a detailed discussion of the changes in the ampacity of the feeder cables of the existing 480V motors (CAR fan motor and control rod drive mechanism shroud fan motor).**

Response:

A. The BVPS-1 and BVPS-2 original CAR fan motors were supplied with a 1.0 service factor. Each motor is rated 300 HP but will operate at 315 BHP during normal full load operation after containment conversion to atmospheric pressure. The motor vendor has stated that motor operation at 315 BHP should not compromise motor life based on an operating temperature of 29C. Note that the CAR fans do not perform a safety-related function.

B. Operation of the CAR fan motors have been reviewed and accepted by the vendor at the EPU (containment at atmospheric pressure) condition. Refer to response to question H.7.A for additional information on the CAR fan motors. The analysis confirmed that the ambient temperature at the motor will be 29C. The motors were designed to operate at 50C ambient. Due to the operating margin in ambient temperature, the vendor concurred that there will not be any loss of life to the motor due to operation at 315 BHP.

C. Existing feeder cables for the CAR and the control rod drive mechanism (CRDM) fan motors were evaluated to confirm that each had adequate ampacity to support plant operation with the containment at atmospheric pressure. The evaluation concluded that the derated cable ampacity (i.e. accounting for all applicable derating factors) exceeded the required load current during normal plant full load EPU operation. Accordingly, life of the existing feeders is not adversely affected by EPU. The results of the evaluation are tabulated in Table 7.

Table 7				
BVPS Unit	**Item**	**Equipment ID**	**Load Current at EPU (AMPS)**	**Derated Cable Ampacity (AMPS)**
1	Containment Air Recirculation Fan	VS-F-1A, B, C	402	438.84
1	Control Rod Drive Shroud Fan	VS-F-2A, B	175	182
1	Control Rod Drive Shroud Fan	VS-F-2C	175	239.27
2	Containment Air Recirculation Fan	2HVR-FN201A	408	551.7
2	Containment Air Recirculation Fan	2HVR-FN201B	408	614.38
2	Containment Air Recirculation Fan	2HVR-FN201 C	408	810.9
2	Control Rod Drive Shroud Fan	2HVR-FN202A1, B1	97	101.78
2	Control Rod Drive Shroud Fan	2HVR-FN202C1, B2	102	115.28
2	Control Rod Drive Shroud Fan	2HVR-FN202A2, C2	102	106.51

H.8 Question: (Applicable to EPU)

Section 9.19.3: Address the impact of the load changes on the 125 V dc system in this section.

Response:

The 125 Vdc system was evaluated for loading changes due to (EPU conditions for both BVPS-1 and BVPS-2. For BVPS-2, there are no plant changes that would impact the design loading capability of the 125 Vdc system, and therefore the 125 Vdc system is adequate for EPU conditions. For BVPS-1, the only change to the 125 Vdc system was the addition of the fast closing Feedwater Isolation Valve (FWIV) circuitry, which was modified during the 1R16 refueling outage in the fall of 2004 at BVPS-1. The engineering change package has been implemented and the revised analysis shows that there is no impact to the design loading capability of the 125 Vdc system. Therefore the 125 Vdc system is adequate for EPU conditions.

H.9 Question: (Applicable to EPU)

Section 9.20

A. Identify the nature and quantity of megavolt-amperes reactive (MVAR) support necessary by each Beaver Valley unit to maintain post-trip loads and minimum voltage levels.

B. Identify what MVAR contributions each Beaver Valley unit is credited in its support of the offsite power system or grid.

C. Identify any changes in the MVAR quantities associated with items A. and B. post EPU.

D. Discuss any compensatory measures necessary to adjust for any shortfalls in item C. above.

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 any information exchanges with the transmission system operator.**

F. **What is the demonstrated capability of the generator in MW output and MVARs?**

G. **Were any Category D events (North American Electric Reliability Council planning standard IA) experienced in the past? If yes, then describe the mitigation measures taken. Provide an evaluation of the Category D faults for EPU conditions.**

H. **Provide details about the model validation for the grid stability study and about on-line contingency capabilities available during EPU conditions.**

I. **On page 9-45 of the submittal, the licensee stated that the instability does not adversely affect the ability to meet General Design Criterion (GDC) 17. Please provide a detailed explanation.**

J. **Did the Pennsylvania, New Jersey, and Maryland interconnection (PJM) review the grid stability studies performed by Power Systems Energy Consulting (PSEC) Group and American Transmission Systems Incorporated (ATSI)? If yes, then provide the results of the PJM review.**

Response:

A. If one of the BVPS units trip, the system around BVPS and the remaining BVPS unit have sufficient reactive capability to support the 345kV system. For loss of BVPS-1, BVPS-2 supplies 332 MVAR, which is well within its capability. Similarly, for the loss of BVPS-2, BVPS-1 supplies 308 MVAR which is well within its capability. For loss of both BVPS units, none of the units will be supplying reactive output to the system however, the area around BVPS is electrically robust and the voltages drop only slightly. Pre-trip BVPS bus voltage is 350.2kV and after the loss of both units the voltage dips only slightly to 349.8kV. These values are based on simulated summer peak transmission system conditions. The pre-trip condition represents a normal system condition with all lines and transformers in service and a normal summer peak load generation dispatch. The post-trip voltage of 349.8 kV represents a system condition representing the loss of two generating units (BVPS-1 and BVPS-2).

The post trip voltage support for the BVPS comes from the 138 kV system line. BVPS SSSTs have the automatic load tap changer to maintain the minimum required bus voltage. As described above, the area around BVPS is electrically robust and loss of generation of one BVPS unit or other nearby single generating unit does not cause significant voltage drop. BVPS station load flow analyses (BVPS-1 and BVPS-2) were performed using minimum 339.8 kV. Even at 339.8 kV, there is adequate voltage available at the loads. Presently required grid voltages are 345 kV to 350 kV. If the grid voltage drops below 343 kV the system operator will begin to take action to bring the grid voltage up to 345 kV.

B. BVPS-1 is modeled in the stability studies as having a maximum reactive capability of 349 MVAR. BVPS-2 is modeled as having a maximum reactive capability of 353 MVAR.

C. The maximum reactive capabilities modeled in the stability studies for the BVPS units was the same for both the 1.4% Uprate and the EPU. BVPS EPU calculations determined that both BVPS-1 and BVPS-2 can supply up to a maximum of 375 MVAR. This is greater than the 349 MVAR for BVPS-1 and 353 MVAR for BVPS-2 modeled in the stability studies.

D. Since the maximum reactive capabilities modeled in the stability studies for the BVPS units is the same for both the current plant operation and the EPU and can be supported by both BVPS units, there are no shortfalls and hence no compensatory measures are necessary.

E. There was no change in MVAR capability modeled for the stability studies, and as stated in the response to question H.9.A, the area around BVPS is electrically robust so there is no impact on the ability to maintain post-trip (one of the two units) voltage levels. The load flow calculations for EPU conditions indicate that the post-trip loads will have adequate voltage for a minimum voltage level of 341kV.

F. The BVPS-1 and BVPS-2 generators are currently rated at 1026 MVA, 923.4 MW, 447 MVAR, 0.90 PF, 22 kV, 75 PSIG. In order to support extended power uprate (EPU). Siemens-Westinghouse evaluated the existing generators for use at EPU and based upon their review the generators are capable of being re-rated from 1026 MVA to 1070 MVA. The re-rated generators will be capable of 1070 MVA, 984.4 MW, 413 MVAR, 0.92 PF, 22 kV, 75 PSIG.

G. In 1997 and again in 1999 FirstEnergy experienced the loss of all generating units (3 – 850 MW units) at the adjacent Bruce Mansfield Station, a North American Electric Reliability Council (NERC) Category D10 event. This loss was absorbed by the system with no loss of transmission facilities and no impact on BVPS. As a result of these events, Bruce Mansfield substation was reconfigured and control schemes were revised to mitigate the possibility and impact of a similar event. Load-flow analysis of the loss of all generation at Bruce Mansfield was included as part of the recently completed FirstEnergy 2005 summer assessment study. This study indicated no thermal or voltage violations should this event occur under system normal conditions.

While the August 14, 2003 event was not considered a Category D event but was rather a chain of events leading to a wide area outage, it is worth noting that BVPS was not significantly impacted by this event. The BVPS units did not trip or experience a loss of offsite power during the event.

FirstEnergy contracted with the GE Power Systems Energy Consulting (PSEC) staff when evaluating the BVPS 10% Uprate request. GE PESC work focused on Dynamic Stability analysis and their findings were fully documented in a report title "Beaver Valley Power Station 10% Uprate Study" dated September 2002. The GE PESC staff considered a number of extreme contingencies (NERC D) events. The study results indicated that the power system is stable for all single-phase faults studied for FirstEnergy BVPS 10% power uprate cases under 2003 peak load and 2004 light load conditions. The system was found to show some instability for some three-phase to ground fault scenarios involving a breaker failure. Due to the low probability of occurrence of extreme contingency events (NERC Category D), ATSI does not routinely plan for system modifications or reinforcements to mitigate risks related to extreme system conditions. ATSI will not require BVPS to mitigate system instabilities due to extreme contingency conditions.

H. The following models were used to represent the generating unit at BVPS:

- Generating Units Model: GENROU - Solid rotor generator represented by equal mutual inductance rotor modeling.
- Excitation Systems Model: EXAC1 - IEEE type AC1 excitation system
- Dynamic Models include the BVPS EPU dynamic models and data for the generator, and exciter.

In order to validate dynamic model and data, the dynamic simulation models were first initialized (i.e. zero input to integrators). After initialization, a no fault run was performed and then a small disturbance run. Finally, a serious disturbance was applied to validate the models.

BV is part of the PJM control area and as such, PJM assumes primary responsibility for performing on-line contingency analysis. However, FirstEnergy's System Control Center also performs on-line contingency analysis. If this analysis indicated a problem that could impact BVPS, FirstEnergy operators would notify PJM.

PJM provides on-line contingency analysis in accordance with their established Nuclear Plant Communications Protocol. PJM Operating procedures provide instructions for Transmission Operators to inform the generating station of potential or actual voltage outside the established limit, contingency element and all corrective measures. PJM will initiate notification to nuclear plants if the PJM Energy Management System (EMS) results indicate nuclear substation voltage outside the established limit and the PJM operator believes he is unable to return system voltages above established limits.

I. The instability discussed on page 9-45 of the EPU Licensing Report is not due to EPU conditions. Instability for certain three phase faults with delayed clearing was initially identified in the system stability studies performed for the 1.4% power uprate. This study was performed using newer and updated software. The 1.4% uprate study model also used updated Grid parameters which included new generation and line parameter changes. The updated study did not consider fault impedance since there is no clear industry guideline available to include that in the analysis, thus the study is considered conservative. A UFSAR change was issued to revise the UFSARs for both units to reflect this instability. This evaluation involves the potential for grid instability for certain 3 phase faults with delayed clearing.

The 10% Uprate study included additional fault scenarios to determine the extent of the instability and possible mitigation techniques. The study concluded that 14 of 43 scenarios resulted in instability resulting in trip of various combinations of the BVPS, Mansfield and AES units. For these scenarios, all other machines in the Duquesne Light system, FirstEnergy system, and the interconnected power systems remained stable. The study showed that there would be sufficient capacity remaining to support the BVPS auxiliary loads following these scenarios that resulted in instability.These faults do not result in the simultaneous failure of both circuits from the single event since the 138 kV power sources would stabilize and have sufficient capacity for the transfer to be successful upon unit trip. These faults do not affect the preferred power systems independence from the onsite power system. These faults do not result in the complete loss of preferred power even though multiple generating stations may trip as a result of these faults prior to the system stabilizing. These faults are considered Category D Events in NERC Planning Standard I A. It is only required to be evaluated for consequences but mitigation of the consequences is at the discretion of the transmission operators. Due to the low probability of occurrence of extreme contingency events (NERC Category D), ATSI does not routinely plan for system modifications or reinforcements to mitigate risks related to extreme system conditions. ATSI will not require BVPS to mitigate system instabilities due to extreme contingency conditions.

Loss of power to both units has already been evaluated due to other initiators such as tornado or earthquake. This instability does not adversely affect the ability to meet GDC 17 criteria to minimize the probility of losing electric power from any of the remaining supplies as a result of, or coincident with, loss of power from the onsite electric power supplies. This is based on the conclusion that the instability will not result in the simultaneous failure of both circuits from the single event, does not affect the preferred power system's independence from the onsite power system, and the 138 kV power sources would stabilize and have sufficient capacity remaining to support the BVPS auxiliary loads. The result of this instability would be the loss of both BVPS units, transfer of station service power from the unit station transformer supply to the 138 kV bus supply. If the transfer were unsuccessful or if the voltage dip were of sufficient duration, emergency loads would be sequenced onto the emergency diesel generators as designed. Operation of the transfer scheme and the emergency diesel generator loading are unaffected.

J. PJM did not review the grid stability studies performed by GE PSEC and ATSI. PJM did conduct a deliverability analysis for all plants in the Duquesne Light Company service territory prior to integration of Duquesne Light, to determine if and how much Capacity Interconnection Rights will be granted to each generating facility. As part of the overall EPU effort, BVPS intends to submit a request into the PJM Generator Interconnection queue to perform system impact studies to evaluate the new generation due to the EPU. This action is being tracked in the BVPS Corrective Action Program.

H.10 **Question:** **(Applicable to EPU)**

Section 10.7

A. **Address the adequacy of the DC system for the first hour of the station blackout (SBO) event for EPU conditions.**

B. **EDG loading will increase due to EPU. The increase loading will reduce the spare capacity. BVPS-1 and 2 utilize emergency AC power from the other unit as an Alternate AC (AAC) power source. Please address the impact of reduced capacity available as the AAC power source.**

Response:

A. During an SBO, station batteries, inverters and related distribution systems are available with capability to cope during the initial one hour period prior to AAC capability. The 125 Vdc system consists of safety and nonsafety-related 125 Vdc buses that supply motive and control power to safety-related and non-safety-related loads. Control power for the 4160 V and 480 V switchgear systems is included among the connected 125 Vdc loads.

   Station batteries, inverters, and related distribution systems were evaluated with respect to EPU for both BVPS-1 and BVPS-2. For BVPS-2, there are no loading changes that would impact the design capability of the station batteries, inverters and related distribution systems, and therefore the 125 Vdc system is adequate for EPU conditions. For BVPS-1, the only change to the 125 Vdc system loading was the addition of the fast closing Feedwater Isolation Valve (FWIV) circuitry, which was modified during the 1R16 refueling outage in the fall of 2004 at BVPS -1. The engineering change for addition of these valves has been completed and does not impact the design capability of the 125 Vdc system. It was concluded that these systems would be available with capability to cope during the initial 1-hour period prior to CC capability.

B. EPU load changes to the Emergency Diesel Generators (EDG) were evaluated. The analyses confirm that during DBA, LOOP, SI, and SBO events that the existing EDG capability is not exceeded. The BVPS-1 EDG loading analysis was updated to include EPU loading for SBO conditions and found within EDG capability (2850 KW). The BVPS-2 EDG loading analysis was updated to include EPU loading for SBO conditions and found within EDG capability (4535 KW). The loading analysis for each unit includes the design basis loading and SBO loading of the other unit. Therefore the EDG is capable of performing its function as the AAC power for EPU.

H.11 <u>Question</u>: (Applicable to RSG & EPU)

Section 10.10.1

A. **Provide details about the impact of containment conversion (CC), replacement steam generators (RSG) and EPU conditions on the environmental qualification (EQ) of the equipment.**

B. **Explain any EQ impact due to main steam line break (MSLB) in the main steam valve house.**

C. **Do any EQ components need replacement due to EPU?**

D. **The EPU submittal asks to increase the reactor power level to 2900 MWt. However, in this section the reactor power level is stated as 2910 MWt. Explain the difference.**

Response:

A. Qualification of equipment is potentially impacted when environmental parameters used for EQ are changed. The impact to EQ due to implementation of containment conversion (CC), BVPS-1 replacement steam generators (RSGs) and extended power uprate (EPU) was evaluated inside and outside the containment for normal operation and post accident conditions. Changes to environmental temperature, pressure and radiological conditions were identified and evaluated. All equipment was found capable of its safety functions without hardware modification, replacement, or further testing.

   The BVPS Equipment Qualification Program maintains DBA temperature and pressure profiles along with post-accident dose information, which are used in the design and procurement of equipment. The EQ profiles and doses were developed to conservatively bound calculated licensing basis environmental conditions in each area of the plant. The revised CC, RSGs, and EPU environmental conditions were compared to the current EQ profiles and doses. In some cases, the existing EQ profiles and doses were found to bound the revised environmental conditions associated with CC, RSGs, and EPU. Where the revised conditions were not completely bounded by the existing EQ profiles and doses, equipment specific vendor EQ qualification reports were reviewed to verify continued equipment capability. Additionally, the EQ profiles and doses are being adjusted to bound the revised conditions.

   Tables 8 and 9 summarize the temperature, pressure and radiological impacts of CC, RSG, and EPU on both normal operating and post accident conditions:

Table 8 Summary of Environmental Parameter Changes Due to CC, BVPS-1 RSGs and EPU			
Plant Change	**Peak Temperature °F**	**Peak Pressure psig**	**Radiation Scale Factor[2]**
Normal Operation Conditions Inside Containment			
CC	No Change	Higher Subatmospheric Range (12.8-14.2 psia)	No Change
RSGs	No Change	No Change	No Change
EPU	No Change	No Change	1.06
Normal Operation Conditions Outside Containment			
CC	No Change	No Change	No Change
RSGs	No Change	No Change	No Change
EPU	No Change	No Change	1.0-1.06
Accident Conditions Inside Containment			
CC	Increase: BVPS-1 5°F BVPS-2 12°F	No EQ Profile Change	No Change
RSG	Included in CC	No EQ Profile Change	No Change
EPU	Included in CC	No EQ Profile Change	LOCA Gamma: 1.19 Beta: 1.17
Accident Conditions Outside Containment			
CC	BVPS-1 - Increased MSVH Temp.	No EQ Profile Change	Varies
RSG	MSVH Temp Increase Starts Earlier	No EQ profile Change	No Change
EPU	BVPS-1 – Increased Temp in MSVH and Service Building BVPS-2 - Increased Temp in MSVH, Service and Auxiliary Buildings	No EQ Profile Change	LOCA FHA Gamma: 1.19 1.264

Notes:

1. More information related to temperature and pressure profile changes are provided in responses to questions H12 A and H12B.
2. Refer to Section 5.11.7 of the EPU Licensing Report for discussion of radiological scale-up factors.
3. Acronyms:
   FHA Fuel Handling Accident (BVPS-2 Fuel Building only)
   LOCA Loss of Coolant Accident

Table 9					
Equipment Qualification Parameter Changes					
Location:	**Parameter**	**BVPS-1**		**BVPS-2**	
		Current Power	**EPU**	**Current Power**	**EPU**
Inside Containment	Temp. normal, °F	105 (Ave.)	No change	105°F	No change
	Press. normal, psia	9.5-11.6	12.8-14.2	9.1-11.6	12.8-14.2
	Radiation normal (Inside Crane Wall), rad γ / rad β	2E7 / 3E6	Note 1	1.7E7 / 3E6	Note 1
	Radiation normal (Outside Crane Wall), rad γ / rad β	4E4 / 3E6	Note 1	4E4 / 3E6	Note 1
	Humidity, normal, %	40-60	No change	30-60	No change
	Temp. accident peak, °F	350	355	333.3	345
	Press. accident, psia	45	No change	45	No change
	Radiation, accident (Inside Crane Wall), rad γ / rad β	4.7E7 / 1.5E8	Note 1	3.4E7 / 1.7E8	Note 1
	Radiation, accident (Outside Crane Wall), rad γ / rad β	8.7E6 / 1.5E8	Note 1	2.0E7 / 1.7E8	Note 1
	Humidity, accident, %	100	No change	100	No change
	Chemical sprays	pH 8.5-10.9 for hr. 1 pH 8.0-9.0 for > 1 hr.	pH 7.0-10.5	pH 8.5-10.5	pH 7.0-10.5
	Water submergence	-	No change	-	No change
Main Steam Valve House	Temp. normal, °F	106.5-113.5	No change	109.2	No Change
	Press. normal, psia	Atmos.	No change	Slightly negative	No Change
	Radiation normal, rad γ	9E2	No change	1E3	No change
	Temp. peak accident, °F	280	475	535	550
	Press. accident, psia	15.5	15	15.12	15.12
	Radiation, accident, rad γ	1.3E5	Note 1	4.24E4	Note 1
Service Building	Temp. normal, °F	120	No change	100.9	No change
	Press. normal, psia	Atmos.	No change	Atmos.	No change
	Radiation normal, rad γ	3E2	No change	1E3	No change
	Temp. peak accident, °F	330	Note 2	419	Note 2
	Press. accident, psia	N/A	14.86	21.16	19.44
	Radiation, accident, rad γ	1E3	Note 1	9.9E4	Note 1

Table 9					
Equipment Qualification Parameter Changes					
Location:	**Parameter**	**BVPS-1**		**BVPS-2**	
		Current Power	**EPU**	**Current Power**	**EPU**
Auxiliary Building	Temp. normal, °F	65-120	No change	60-120	No change
	Press. normal, psia	Atmos.	No change	Atmos.	No change
	Radiation normal, rad γ	Varies	No change	Varies	No change
	Temp. peak accident, °F	Varies	No change	Varies	Note 2
	Press. accident, psia	15.51	No change	15.26	No change
	Radiation, accident, rad γ	Varies	Note 1	Varies	Note 1

Notes:

1. EPU Dose Scaling Factors
   - Normal Operation (depending on source):
     1.06 Reactor core, Irradiated fuels/objects or N-16 in RCS loops sources
     1.0 Primary coolant activity and down stream sources
   - Accident Conditions:

	LOCA
Gamma	1.19
Beta	1.17

2. MSLB increases the temperature due to EPU, but equipment in this area does not require qualification for this event.

B. The combined impact of containment conversion (CC), EPU and BVPS-1 replacement steam generators (RSGs) on environmental parameters in the BVPS-1 and BVPS-2 Main Steam Valve House used for equipment qualification was evaluated to ensure that all EQ equipment remains qualified in these areas to perform all required safety related functions.

   During a MSLB outside containment, changes to the environmental conditions due to CC, EPU and RSGs used for qualification of equipment in the Main Steam Valve House are summarized as follows (refer to the response to question H.12.B for more information on pressure and temperature profiles):

   1. The pressures anticipated for breaks in this area are bounded by the existing pressure profile.
   2. The temperatures anticipated for breaks in this area exceeds the existing profile. A revised EQ temperature profile was established to bound the peak temperatures resulting from postulated breaks in this area.

To reconcile these parameter changes, the equipment items in the Main Steam Valve Houses were evaluated to define their safety functions. The qualification of equipment affected by these conditions was addressed by one of the following methods:

1. The equipment's safety function can be performed by alternate or redundant equipment located in other plant areas in which the environments are not impacted by the postulated accident in the Main Steam Valve House.
2. The equipment's safety function is performed prior to exposure to the peak accident temperatures or equipment's temperature threshold. For example, the required safety function for the fast acting feedwater isolation valve actuators is performed prior to exceeding the environmental qualification limit.

C. No EQ components need to be replaced due to containment conversion (CC), BVPS-1 replacement steam generators (RSGs) or extended power uprate to 2900 MWt (EPU). All EQ components were shown to remain qualified for the combined environmental changes due to CC, RSGs and EPU.

D. At EPU conditions, the reactor thermal power will be 2900 MWt while the NSSS power will be 2910 MWt. The NSSS power includes both reactor thermal (i.e., core) power of 2900 MWt and net RCS heat input of 10 MWt. Refer to Section 2.1.1.2 of the EPU Licensing Report for additional details.

H.12 <u>Question</u>: (Applicable to RSG & EPU)

Section 10.10.3

A. Provide a comparison of the revised inside containment LOCA/MSLB temperature and pressure profiles to the current profiles.

B. Provide a comparison of the revised temperature and pressure profiles inside the main steam valve houses and the service building to the current profiles.

C. Describe the scaling factors used to determine the gamma and beta radiation total integrated dose (TID) values for post-EPU conditions.

D. Describe the shielding/reduction methods used for beta radiation for post-EPU equipment qualification, including the junction boxes with weep holes or open sides.

E. This section indicates that the alternative test data was used to qualify equipment. Provide details of the alternative test data.

Response:

A. Revised EQ temperature profiles were developed to address the combined effects of containment conversion (CC), BVPS-1 replacement steam generators (RSGs) and extended power uprate to 2900 MWt (EPU). These profiles were included as Figures 7-1 for BVPS-1 and 7-2 for BVPS-2 in Enclosure 2 to the CC LAR 317/190 submitted in FENOC letter No. L-04-073 dated June 2, 2004.

Revised EQ pressure profiles were developed to address the combined effects of CC, RSGs and EPU. The nominal containment design internal pressure for both BVPS-1 and BVPS-2 is 45 psig, which is not challenged by the revised profile even though the post accident pressures increase. The related analyses are described in Section 4 of Enclosure 2 of the CC LAR 317/190 with results provided in Tables 4-16, 4-17, 4-18, and 4-19 of the CC LAR, and summarized Table 10

Table 10

	MSLB	LOCA
BVPS-1		
Current, psig	44.2	40.0
After CC, RSG, EPU, psig	42.6	43.3
BVPS-2		
Current, psig	40.9	44.7
After CC and EPU, psig	39.3	44.9

B. The main steam valve house (MSVH) profiles for BVPS-1 and BVPS-2 are shown in the attached figures. The curve representing the combined effects of containment conversion (CC), BVPS-1 replacement steam generators (RSGs) and extended power uprate (EPU) are shown along with the existing profiles.

Figure 1 is the BVPS-1 MSVH temperature profile

Figure 2 is the BVPS-2 MSVH temperature profile

The BVPS-1 and BVPS-2 Service Building temperature profiles are not included since there is no EQ equipment that responds to accidents that increase the temperature of the Service Buildings.

The pressure profiles for the BVPS-1 and BVPS-2 MSVH and Service Buildings are not included since the limiting condition is peak pressure. The existing EQ peak pressure bounds the EPU peak pressure results. The EPU peak pressure results are provided in Table 9.

Figure 1
BV-1 MSVH Temperature vs Time

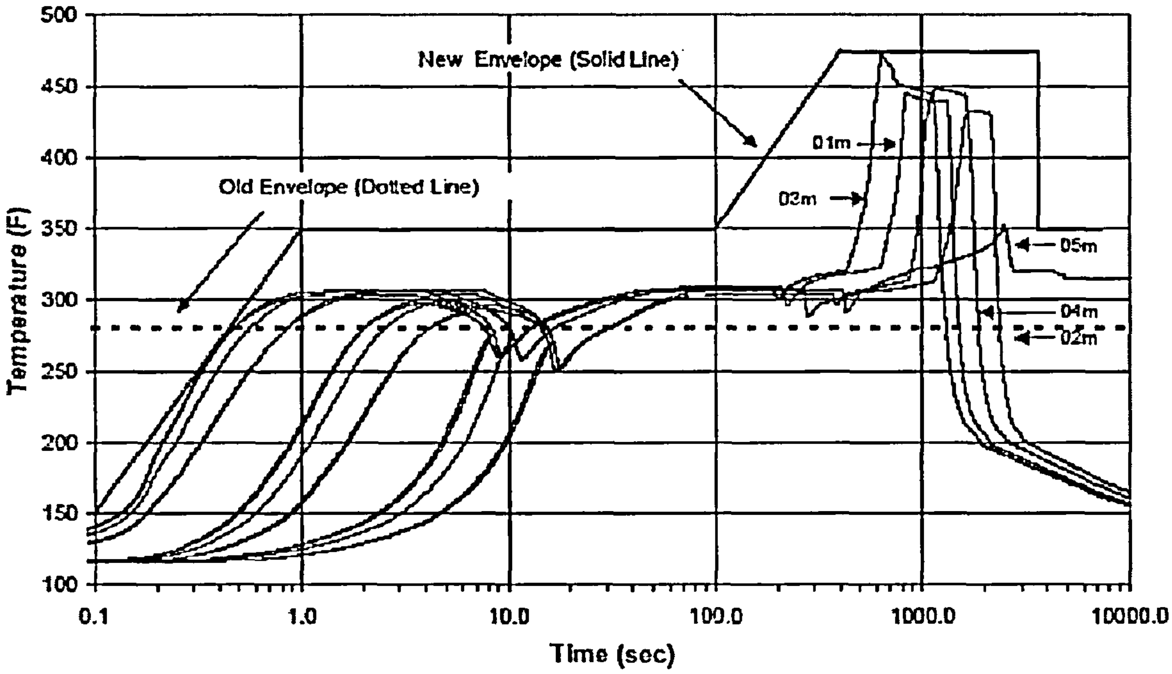
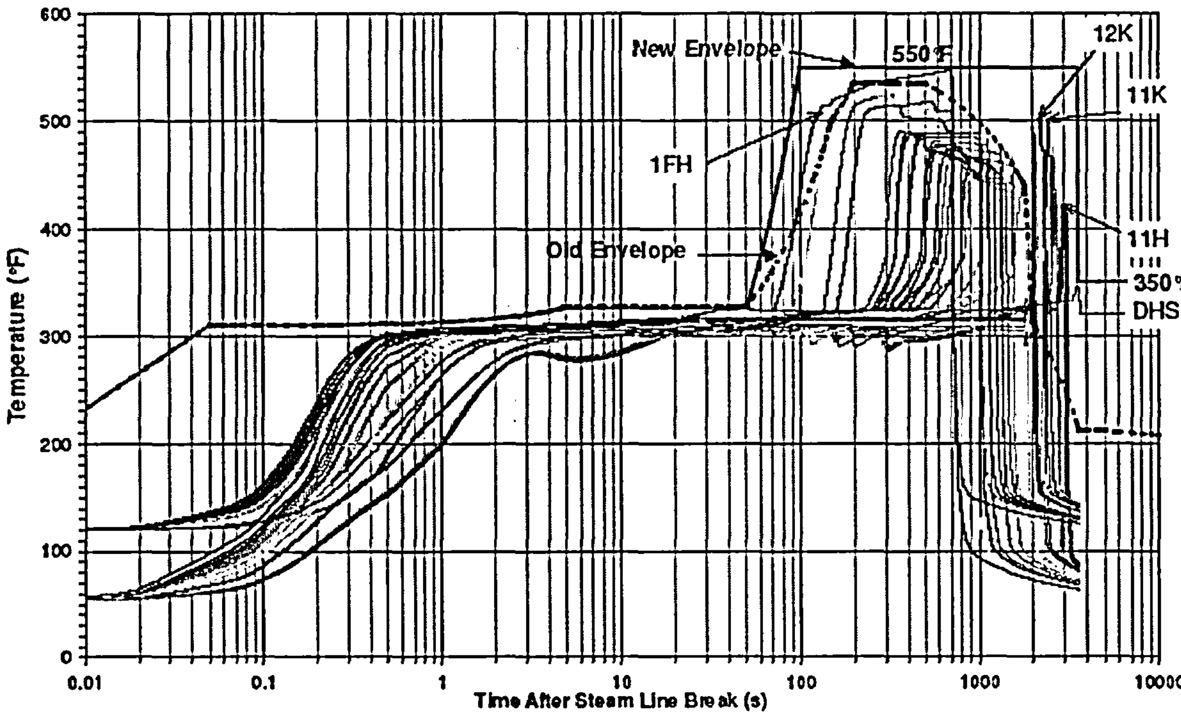


Figure 2

**BVPS-2 Main Steam Valve House
EQ Temperature Envelope**



C. The impact of EPU on the post-LOCA EQ gamma and beta radiation doses is evaluated based on a comparison of the source terms developed based on the original core inventory used to develop the EQ doses, to the EPU source terms. The approach utilizes scaling techniques based on a source term comparison, rather than developing actual integrated dose estimates at the various zones/component-specific locations, using the new core inventory. The scaling factors used to determine the gamma and beta radiation TID values for EPU conditions are discussed in Section 5.11.7 of the EPU Licensing Report (Enclosure 2 of EPU LAR 302/173).

D. Beta radiation emitted from a radioisotope has a limited range in air depending on the energy level of the beta particle. It is also effectively shielded by metals and most other materials. As a consequence, the accident beta dose from an infinite cloud in the containment is reduced to a finite cloud for dose receptors inside metal enclosures such as junction boxes and pipes by shielding out the containment atmosphere sources located outside the metal enclosure and by the limited range of the Betas once they are within the enclosure.

   Data presented in the EPRI EQ Reference Manual (Reference 1) indicate that virtually full attenuation is achieved within the first 1 mm (39.4 mils) of insulating material. Even thinner metallic sections will fully attenuate the beta radiation. This data clearly indicates that external beta radiation will be virtually insignificant for any component within a sealed enclosure or with active internals shielded from the external beta radiation by some intervening structure.

   Beta dose reduction factors are based upon calculations that determined the beta dose resulting from LOCA isotopes for both the infinite cloud and for the internal volumes of a spectrum of pipe diameters of 20 foot in length were applied. This analysis uses the empirical Loevinger equation to ratio the infinite cloud and pipe internal volume beta doses. Also, cable reduction factors are based on IE Bulletin 79-01B, Environmental Qualification of Class 1E Equipment and the DOR Guidelines.

   Equipment that has sealed metal covers is effectively shielded from beta radiation. A typical metal body for an ASCO solenoid valve is 0.081 to 0.125 inches thick with the minimum thickness of the coil housing being 0.050 inches, i. e. 50 mils. As identified by the EPRI EQ Reference manual a beta reduction of 100 would be obtained by a unit density cable jacket of 70 mils (70 mils/7.9 = 8.9 mils of steel). A reduction in the beta exposure can result from the shielding of the casing either completely if sealed to the Containment atmosphere or partially if not sealed but a limited free volume is available for the Containment accident atmosphere with beta emitting isotopes to fill. Reduction factors were applied to cables in vented junction boxes by modeling the internal volumes in the form of a finite volume cylindrical source.

The beta dose reduction factors used are summarized as follows:

1. Enclosures with a effective diameter of 12 inches or less have a beta reduction factor of 2
2. Enclosures with a effective diameter of 4 inches or less have a reduction factor of 4
3. Cable jacket material has been determined to provide effective beta shielding to the cable insulation on the conductors. Cable jackets of 30 mils thickness with unit density ($1 gm/cm^3$) provide a reduction factor of 10
4. For cable jackets of 15 mils the beta reduction factor is obtained by the square root of the 30 mil reduction, i.e. $(10)^{1/2}=3.16$
5. Cable jackets of 70 mil thickness provide a reduction factor of 100
6. Metal enclosures greater than 10 mils thick (30 gauge) provide a reduction factor of greater than 100.

Reference:

1. EPRI Nuclear Power Plant Equipment Qualification Reference Manual TR-100516Project RP 1707 by P. Holzman and G. Sliter.

E. No alternative tests were required or conducted to demonstrate qualification of EQ equipment at either BVPS unit. The referenced discussion in EPU Licensing Report Section 10.10.3 reflected the possibility that application of alternative test data might be required to justify the qualification of some equipment. However, the detailed qualification effort was completed without the need for alternative test data.

The revised environmental conditions, combining the effects of containment conversion (CC), BVPS-1 replacement steam generators (RSGs) and extended power uprate to 2900 MWt (EPU) were compared to the current EQ profiles/doses. In cases where the existing EQ profiles/doses do not bound the environmental conditions associated with CC, RSGs and EPU, equipment specific vendor EQ qualification reports were reviewed to ensure that the documented vendor qualification testing bounds the revised environmental conditions. This verification was successfully accomplished using equipment vendor qualification reports existing in BVPS records since the equipment was procured.

I. Instrumentation and Controls

I.1 Question: (Applicable to EPU)

Plant Licensing Requirements Manual (LRM) 3.8 (Leading Edge Flow Meter (LEFM)), action 1b, requires the use of feedwater venturis for performing calorimetric heat balance calculations when the LEFM is inoperable and also requires thermal power to be reduced to 98.6% of rated thermal power (RTP) measured when the LEFM is not in service, until the LEFM is restored to operable status. This 98.6% thermal power is equivalent to the original 100% licensed thermal power, prior to the use of the LEFM with a 2% margin added, per Title 10 of the *Code of Federal Regulations* (10 CFR), Part 50, Appendix K, to assure that ECCS analyses remain valid. Venturi loops universally used for measuring feedwater flow are of known accuracy so that the 2% Appendix K margin is assured and generally increased when venturis are fouled during prolonged use. Venturi conditions at BVPS-1 and 2, however, raise concerns with regard to adequacy of ECCS analyses.

In a public meeting conducted by the NRC staff on September 17, 2004, regarding the use of ultrasonic flow meter (UFM) devices for feedwater flow measurement, the licensee's staff stated that BVPS-1 and 2 are essentially identical, but for most of its life, BVPS-2 has produced about 1.5% more power than BVPS-1, hence, violating Appendix K requirements. It was concluded therefore, that with both units using venturis for measuring feedwater flow, BVPS-2 was overpowering by about 1.5%, as claimed to have been confirmed by the newly installed LEFM. Using the LEFMs for feedwater flow measurement, power at BVPS-2 was reduced by 1.5% to match power with BVPS-1.

The licensee's staff stated that the LEFM system installed at BVPS-1 provided readings that were essentially the same as the BVPS-1 feedwater venturi meters and, therefore, validating the accuracy of the LEFM with the venturi loop. However, a pre-installation review of various balance of plant indications at BVPS-2 (including generator electric output indication), not a vary precise measurement of reactor power, revealed an overpower of 1.5%. The LEFM installation at BVPS-2 identified that the venturi measurements of feedwater flow indicated 40 MWt power less than that indicated by the LEFM measurements, which is approximately 1.5% of BVPS-2 RTP. The venturis used for measuring feedwater flow at both units, prior to the use of LEFMs, were laboratory-calibrated.

<u>NRC Staff's Concern</u>
As stated by the licensee, venturis for both units were laboratory-calibrated and their measurement uncertainty is expected to remain the same, per American Society of Mechanical Engineers (ASME) Standards PTC 6 and 19.1. The licensee, however, has not explained the cause of the difference in venturi measurements between BVPS-1 and 2 and has not identified corrective measures for assuring better accuracy of feedwater flow at BVPS-2, when the LEFM is not in service, so that the required Appendix K 2% margin is maintained above indicated power.

Furthermore, the licensee needs to reconcile views presented by Caldon to the Advisory Committee on Reactor Safeguards (ACRS) on July 8, 2004 (ADAMS Accession No. ML042080030), regarding use of venturis for confirming accuracy of their LEFM instruments when used in power uprates. Caldon has stated that venturis can not be used to confirm accuracy of their instrument because preponderance of data show that in general, nozzles/venturis can only be counted on to measure accuracy within an uncertainty of ± 1.5%.

Response:

At BVPS-1, there is agreement between the feedwater venturis, the LEFM and results from a test performed in accordance with American Society of Mechanical Engineers (ASME) Standards PTC 6 and 19.1 in 2003, with the replacement of the High Pressure Turbine. There are no discrepancies at BVPS-1 between any of the plant measurements that are indicative of thermal power.

At BVPS-2 the feedwater pump suction venturis and LEFM indications are in agreement and were calibrated by Alden Laboratories. Root causes of venturi biases on BVPS-2 include calibration accuracy, a bias due to installation effects, and an extrapolation bias brought about by tap or nozzle imperfections. Accuracy impacts due to these effects are common in feedwater nozzles, and because they manifest themselves at Reynolds Numbers above the calibration range, they can not be detected. Typical practice of allowing for uncertainties in the range of 1.4 to 1.5% for feedwater nozzles provides adequate margin to account for these effects, as demonstrated at BVPS-2.

There was an extensive investigation into the discrepancy between the BVPS-2 feedwater venturi flow indications and other plant parameters. Scatter in the available plant parameter indications of power was within the aggregate uncertainties of the plant parameters and the venturis. Despite the scatter, however, all plant parameters indicated a non-conservative bias in the feedwater venturis. Therefore, in developing a procedure for use when the LEFM is out of service, the conservative decision was made to reduce plant power by an additional 40MWt (the amount of the bias) in accordance with LRM requirements when the LEFM is not available. With these constraints, utilizing the LEFM or a power reduction in accordance with the LRM, BVPS-2 performs essentially the same as BVPS-1.

To ensure conservative operation of BVPS-2 when the LEFM is not in service, the required Appendix K 2% margin is maintained by reducing the indicated power level to 98.6% as indicated by the feedwater venturis after correcting for the 40Mwt bias in the feedwater venturis. This process is controlled through the Licensing Requirements Manual (LRM) for conditions where the LEFM is either out of service or the quality of the LEFM data is identified as poor (the quality check is performed automatically by the LEFM). Reactor power is reduced to 2612MWt, a 40MWt reduction from the 2652MWt pre-Appendix K uprate value. (Note, BVPS-1 is controlled through the Licensing Requirements Manual for conditions where the LEFM is either out of service or the quality of the LEFM data is identified as poor, requires reactor power be reduced to 2652MWt, the pre-Appendix K uprate value. Mark-ups of the LRM are contained in Enclosure 1, Attachment C-1 and C-2 addressing the EPU.)

With respect to the views presented by Caldon to the Advisory Committee on Reactor Safeguards (ACRS) on July 8, 2004 (ADAMS Accession No. ML042080030), regarding use of venturis for confirming accuracy of their LEFM instruments when used in power uprates, the approach taken at BVPS is entirely consistent and in agreement with Caldon's position. Feedwater nozzles are not as accurate as the LEFM (as has been demonstrated by the experience at BVPS-2) and, as a consequence, they can not be used to verify the accuracy of the LEFM. This does not mean that the LEFM accuracy can not be verified. Caldon has produced additional guidance in the form of Customer Information Bulletin CIB-119, consistent with the information contained in Caldon Topical Reports ER-80P, ER-160P and ER-157P on how the LEFM accuracy can be verified. BVPS installations and commissioning processes are consistent with the recommendations contained in these documents.

I.2 <u>Question</u>: (Applicable to RSG & EPU)

Section 5.10.3 in Enclosure 2 of the licensee's application defines margin as the difference between the total allowance (TA) and the channel statistical allowance (CSA) and states that the "acceptance criterion for the RTS/ESFAS [reactor trip system/engineered safety features actuation system] setpoints is that the margin is greater than or equal to zero." Section 5.10.4 states that all of the RTS/ESFAS functions have acceptable margins, and, therefore, are acceptable for the nuclear steam supply system (NSSS) power of 2910 MWt. Please explain what is included in TA and its basis. Also explain how CSA is calculated. Also explain the relationship between the proposed EPU of 2900 MWt and the NSSS power of 2910 MWt.

Response:

The methodology for the uncertainty calculations used for BVPS-1 and BVPS-2 was previously reviewed by the staff via Westinghouse WCAPs for BVPS-1 and BVPS-2. The WCAP reference for BVPS-1 is WCAP-11419 Rev. 2, "Westinghouse Setpoint Methodology for Protection Systems Beaver Valley Power Station – Unit 1" dated December 2000, and the WCAP for BVPS-2 is WCAP-11366 Rev. 4, "Westinghouse Setpoint Methodology for Protection Systems Beaver Valley Power Station – Unit 2" dated December 2000. Upon conclusion of this review the staff issued Amendment 239 to facility license DRP-66 and Amendment 120 to facility license NPF-73 via a July 30, 2001 letter titled, "BEAVER VALLEY POWER STATION, UNIT NOS. 1 AND 2 – REVISED IMPLEMENTATION PERIOD FOR LICENSE AMENDMENT NOS. 239 AND 120, (TAC NOS. MB0848 AND MB0849)". These WCAPs have been revised to address the NSSS power level of 2910MWt and continue to demonstrate acceptable margins.

The NSSS power of 2910MWt is based on a core power of 2900MWt and the resulting net heat input after consideration of system losses is 10MWt provided by the Reactor Coolant Pumps.

I.3 Question: (Applicable to RSG & EPU)

Trip setpoints and allowable values (AVs) in Table 5.10-2 and those for overtemperature ΔT and overpower ΔT reactor trip were calculated using documents listed in Section 5.10.5 of Enclosure 2. Provide these documents for the NRC staff's review. Provide references only if the listed topical reports (WCAPs) were previously reviewed and approved by the NRC staff.

Response:

The methodology for the uncertainty calculations used for BVPS-1 and BVPS-2 for the trip setpoints and Allowable Values in EPU Licensing Report Table 5.10-2 including the Overtemperature ΔT and Overpower ΔT setpoints was previously reviewed by the staff via Westinghouse WCAPs for BVPS-1 and BVPS-2. The WCAP reference for BVPS-1 is WCAP-11419 Rev. 2, "Westinghouse Setpoint Methodology for Protection Systems Beaver Valley Power Station – Unit 1" dated December 2000, and the WCAP for BVPS-2 is WCAP-11366 Rev. 4, "Westinghouse Setpoint Methodology for Protection Systems Beaver Valley Power Station – Unit 2" dated December 2000. Upon conclusion of this review the staff issued Amendment 239 to facility license DRP-66 and Amendment 120 to facility license NPF-73 via a July 30, 2001 letter titled, "BEAVER VALLEY POWER STATION, UNIT NOS. 1 AND 2 – REVISED IMPLEMENTATION PERIOD FOR LICENSE AMENDMENT NOS. 239 AND 120, (TAC NOS. MB0848 AND MB0849)". The WCAPs referenced in EPU LR Section 5.10.5 have been revised to address the NSSS power level of 2910MWt and continue to demonstrate acceptable margins.

I.4 Question: (Applicable to RSG & EPU)

Explain overtemperature ΔT and overpower ΔT formulae in Table 3.3-1 and function of lead/lag filters to accommodate the revised time constants as mentioned in Section 9.25.2 of Enclosure 2. Also clarify why these formulae have different lead/lag compensators and number of time constants than those used for calculating these two reactor trip functions in the Westinghouse Standard Technical Specifications.

Response:

A comparison of the Overtemperature ΔT and Overpower ΔT equations in Table 3.3-1 for BVPS-2 and the Westinghouse Standard Technical Specifications (NUREG-1431 Volume I Rev. 3) shows the equations have the identical mathematical form, including the same lead/lag time compensators and number of time constants. The presently installed lead/lag cards contain course and fine adjustments so that each time constant can be implemented without plant hardware changes.

The existing BVPS-1 Overtemperature ΔT (OTΔT) and Overpower Δ (OPΔT) equations shown on BVPS-1 Technical Specifications pages 3/4 3-5 and 3/4 3-5a have two deviations from the Westinghouse Standard Technical Specifications (NUREG-1431, Volume I, Revision 3). The existing BVPS-1 OTΔT and OPΔT equations do not include lag compensators (annotated as τ3 and τ6 in the Westinghouse Standard Technical Specifications). Additionally, the existing BVPS-1 OTΔT and OPΔT equations do not include a lead/lag compensator (annotated as τ1 and τ2 in the Westinghouse Standard Technical Specifications).

The proposed BVPS-1 OTΔT and OPΔT equations have been revised to include the addition of lag compensators (annotated as τ3 and τ6 in the Westinghouse Standard Technical Specifications). The proposed lag compensators for the OTΔT and OPΔT equations are annotated as τ4 and τ5 in the BVPS-1 Technical Specifications. The addition of lag compensators will modify the existing BVPS-1 OTΔT and OPΔT equations such that lag compensation is consistent with the mathematical form shown in the Westinghouse Standard Technical Specifications. The lag compensators were added to increase operating margin by reducing signal noise impact to the trip functions.

The remaining mathematical difference between BVPS-1 OTΔT and OPΔT equations and the Westinghouse Standard Technical Specifications equations is the lead/lag transfer function (annotated as τ1 and τ2 in the Westinghouse Standard Technical Specifications). The hardware to provide this specific lead/lag compensation function has never been installed at BVPS-1. Therefore it would be inconsistent to show time constants in the Technical Specifications that do not physically exist in the plant. The existing BVPS-1 safety analysis did not require the use of the lead/lag compensator function. The proposed OTΔT and OPΔT parameters were established to optimize operating margin within the constraints of the safety analysis.

Note that the equivalent lead/lag compensator at BVPS-2 shows τ1 and τ2 set to zero, thereby effectively removing the lead/lag compensator from the equations and thereby providing BVPS-1 and BVPS-2 with mathematically equivalent equations.

I.5 <u>Question</u>: **(Applicable to RSG & EPU)**

The NRC staff has determined that setpoint AVs established by means of ISA 67.04, Part II, Method 3 (Method 3), do not provide adequate assurance that a plant will operate in accordance with the assumptions upon which the plant safety analyses have been based. These concerns have been described in various public meetings. The presentation used in public meetings in June and July 2004 to describe the NRC staff's concerns is available on the public website under ADAMS Accession No. ML041810346.

The NRC staff is currently formulating generic action on this subject. It is presently clear, however, that the NRC staff will not be able to accept any requested Technical Specification (TS) changes that are based upon the use of Method 3, unless the method is modified to alleviate the NRC staff's concerns. In particular, each setpoint limit in the TSs must ensure at least 95% probability with at least 95% confidence that the associated action will be initiated with the process variable no less conservative than the initiation value assumed in the plant safety analyses. In addition, the operability of each instrument channel addressed in the setpoint-related TSs must be ensured by the TSs. That is, conformance to the TSs must provide adequate assurance that the plant will operate in accordance with the safety analyses. Reliance on settings or practices outside the TSs and not mandated by them is not adequate.

The NRC staff has determined that AVs computed in accordance with ISA Method 1 or 2 do provide adequate assurance that the safety analysis limits will not be exceeded. The NRC staff has also determined that an entirely different approach, based upon the performance of an instrument channel rather than directly upon the measured trip setting, can also provide the required assurance. This alternative approach, designated performance-based TSs (PBTSs), sets limits on acceptable nominal setpoints and upon the observed deviation in the measured setpoint from the end of one test to the beginning of the next. This approach has been accepted for use at Ginna, and is discussed in a safety evaluation (SE) available via ADAMS at Accession No. ML041180293. The referenced SE is specific to Ginna, and is cited here only as a general example for other plants. It is up to the licensee to modify the approach as necessary to meet the indicated objectives for the particular plant(s) in question. In addition, licensees are welcome to propose alternative approaches that provide the indicated confidence, but such alternative approaches must be presented in detail and must be shown explicitly to provide adequate assurance that the safety analysis assumptions will not be violated.

The Nuclear Energy Institute (NEI) has indicated an intent to submit a white paper concerning this matter for NRC consideration. Receipt of that white paper is anticipated in late October or early November 2004. Licensees may choose to endorse whatever approach and justification is described in that white paper, or to act independently of the NEI. If the NEI approach is found to be acceptable to the NRC staff, it will be necessary for each licensee who chooses to use it to affirm that the salient conditions, practices, etc. described in it are applicable to their individual situations.

Please indicate how you wish to proceed in regard to the setpoint-related TS changes addressed in your request. The following are examples of acceptable actions:

A. **Demonstrate that the approach that you have used to develop the proposed limits provides adequate assurance that the plant will operate in accordance with the safety analyses. Show that operability is ensured in the TSs.**

B. **Suspend consideration of setpoint-related aspects of your request pending generic resolution of the NRC staff's concern.**

C. **Revise your request to incorporate Method 1, Method 2, or PBTSs.**

D. **Revise your request to incorporate some other approach that you demonstrate to provide adequate confidence that the plant will operate in accordance with the safety analyses and show that operability is ensured in the TSs.**

Response:

The methodology to determine the Allowable Values for the BVPS-1 and BVPS-2 Technical Specifications protection setpoints are not based on any of the methods as described in the ISA recommended practice document (ISA-RP67.04-1994, Part II or ISA-RP67.04.02-2000). The Westinghouse method used for the BVPS-1 and BVPS-2 Technical Specification determines a performance based Allowable Value. As noted in WCAP-11419 Rev. 2, and WCAP-11366 Rev. 4 (referenced below), the Allowable Value is satisfied by verification that the channel "as left" and "as found" conditions about the nominal trip setpoint are within the Rack Calibration Accuracy. The methodology for the uncertainty calculations and the Allowable Values used for BVPS-1 and BVPS-2 was previously reviewed by the staff via Westinghouse WCAPs for BVPS-1 and BVPS-2. The WCAP reference for BVPS-1 is WCAP-11419 Rev. 2, "Westinghouse Setpoint Methodology for Protection Systems Beaver Valley Power Station – Unit 1" dated December 2000, and the WCAP for BVPS-2 is WCAP-11366 Rev. 4, "Westinghouse Setpoint Methodology for Protection Systems Beaver Valley Power Station – Unit 2" dated December 2000. Upon conclusion of this review the staff issued Amendment 239 to facility license DRP-66 and Amendment 120 to facility license NPF-73 via a July 30, 2001 letter titled, "BEAVER VALLEY POWER STATION, UNIT NOS. 1 AND 2 – REVISED IMPLEMENTATION PERIOD FOR LICENSE AMENDMENT NOS. 239 AND 120, (TAC NOS. MB0848 AND MB0849)". The methodology used in the above WCAPs is the same methodology used for the current Technical Specification submittal.

The criterion for the performance based Allowable Value is controlled by both plant procedures and the Technical Specifications. In the BVPS Technical Specifications, Sections 3/4.3.1 and 3/4.3.2, the requirement is to verify that the instrumentation is operable. This verification is performed every 92 days by performance of the Channel Operability Test (COT) confirming that the channel meets the stated Allowable Value. Because the Allowable Values for BVPS are based on the Rack Calibration Accuracy, it then follows that the channel must be within the calibration accuracy to be considered operable. As noted in the referenced WCAPs, the setpoint methodology assumes that the channel is always returned to within the Rack Calibration Accuracy and because the Allowable Value is based on the Rack Calibration Accuracy, this assumption will be met in order for the channel to be considered operable.

J. Pressurized Thermal Shock (PTS)

J.1 Question: (Applicable to EPU)

FENOC's [FirstEnergy Nuclear Operating Company's] EPU submittal states in Section 4.1.2.5, that "...neutron fluence projections have increased versus those calculated fluence projections reported in WCAP-15571." In addition, it is stated that the fluence used in WCAP-15570, the applicable report for the BVPS-1 pressure temperature (PT) limit curves, bound the first portion of the uprating. However, Section 4 in WCAP-15570 states that the fluence values are from Section 6 of WCAP-15571. Comparison of the values verified that this is the case. Please clarify how the EPU uprated neutron fluence values for BVPS-1 were derived/calculated, where the uprated neutron fluences are reported, and how the changes made to the BVPS-1 1/4T and 3/4T neutron fluences (to account for the uprated power conditions) will impact the NRC staff's requests made in RAI 4.1.2-3 (on PT limit changes) and in RAI 4.1.2-7 (on uprated upper shelf energy (USE) assessments).

Response:

The BVPS-1 planned power increases were to occur in two stages; the 1.4% power measurement uncertainty recapture power uprate to 2689 MWt (implemented previously), followed by an 8% extended power uprate (EPU) for a total power increase of 9.4% to 2900 MWt. The power uprate that was planned at the time when WCAP-15569, WCAP-15570 and WCAP-15571 were written to evaluate the Capsule Y surveillance results was based upon a total power increase of 5.5% at the end of Cycle 15 (April 2003). The fluence analysis documented in WCAP-15571 included a fuel cycle specific evaluation for Cycles 1 through 13, a projection for Cycle 14 assuming the pre-uprate core power, and further projections through 45 effective full power years assuming a 5.5% power uprate at the end of Cycle 15 using the most conservative (highest) L4P core fluence and increasing it by 5.5%. Based on these assumptions, the fluence values reported in WCAP-15571 would bound the first stage (1.4%) of the overall 9.4% power uprate, but will not fully address the second stage due to the conservative L4P cycle fluence assumed.

To support the BVPS-1 EPU for a total power increase of 9.4%, additional neutron fluence analysis was performed for a core power increase to 2900 MWt, which was assumed to occur in June 2003 (Cycle 16). This additional analysis for EPU is discussed in Section 6.5 of the EPU Licensing Report. The neutron fluence projections for the EPU to 2900 MWt are reported in Table 6.5-1A of the EPU Licensing Report and were used in the reactor vessel integrity evaluations reported in Section 4.1.2 of the EPU Licensing Report.

This RAI also requested discussion on "how the changes made to the BVPS-1 1/4T and 3/4T neutron fluences (to account for the uprated power conditions) will impact the NRC staff's requests made in RAI 4.1.2-3 (on PT limit changes) and in RAI 4.1.2-7 (on uprated upper shelf energy (USE) assessments." The impact of the fluences associated with uprated conditions on the PT curves (as explained in more detail in the response to RAI 4.1.2-3) was to limit the effective applicability of the PT curves by a small amount from that calculated in WCAP-15570. The change in applicability of the 28 EFPY PT curve to an applicability of 27.58 EFPY bears this out.

The impact on the Upper Shelf Energy values was assessed using the uprated fluence conditions and, as noted in the EPU Licensing Report Section 4.1.2.5, these higher fluence conditions impacted the 1/4T fluence value at 28 EFPY by less than 1%. This small change in 1/4T fluence has no measurable impact on the USE values. The 1/4T EOL fluence values are provided with the response to question J.7 of this RAI, Table 11a. It should be noted that the fluence values for the 3/4T location were not recalculated given the results of the 1/4T evaluation show no measurable change.

J.2 Question: (Applicable to EPU)

Regarding the BVPS-1 PTS assessment reported in WCAP-15569, it is stated in Section 1, that the neutron fluences used for the RT_{PTS} value calculations were derived from the WCAP-15571 (BVPS-1 Capsule Y Report, November 2000). Tables 6 and 7 in WCAP-15569 confirms this to be the case. The NRC staff has determined that WCAP-15571 does not clearly indicate the reported neutron fluence values, as derived from the Capsule Y dosimetry measurements, and calculations were appropriately increased to account for the 8% uprated power conditions. Please clarify how the neutron fluence values for the clad/base-metal interface were calculated to account for the 8% power conditions, where the uprated neutron fluences are reported, and how the changes made to the BVPS-1 neutron fluences for the clad/base-metal interface (to account for the uprated power conditions) will impact the calculated, uprated RT_{PTS} values for the BVPS-1 reactor vessel (RV) beltine base-metal and weld materials.

Response:

As described in the response to question J.1 above, the BVPS-1 fluence projections associated with the full 9.4% EPU were developed as described in Section 6.5 of the EPU Licensing Report. These fluence values, based on the full EPU, were then used in the PTS assessment for the BVPS-1 reactor vessel as described in Section 4.1.2 of the EPU Licensing Report. The updated fluences and PTS values for EPU are included in the EPU Licensing Report.

J.3 Question: (Applicable to EPU)

Table 4.1.2-3A indicates reduced applicability of the BVPS-1 PT limit curves from 22, 28 and 45 effect full power years (EFPYs) of operation (as previously referenced in WCAP-15570) to 21.78, 27.58, and 44.0 EFPYs. However, the NRC staff's review of WCAP-15570 indicates that the WCAP did not include any technical bases or calculations for reducing the applicability of the curves to 21.78, 27.58, and 44.0 EFPYs, as based on the neutron fluence values associated with the 8% uprated power conditions. Please clarify how the reductions in the applicability of the PT curves to 21.78, 27.58, and 44.0 EFPYs were calculated (as based on 8% uprated power conditions) and where the bases for these reductions were reported.

Response:

The PT limit curves for 22, 28 and 45 EFPY were developed using fluence projections from WCAP-15570 (BVPS-1 Capsule Y). This report accounted for an uprate but only up to 5.5%. After this report was completed, it was decided that the extended power uprate (EPU) would extend up to 9.4% total power increase. For BVPS-1, the EFPY values identified in Table 4.1.2-3A of the EPU Licensing Report reflect the entire 9.4% EPU assuming EPU implementation in spring of 2003 (Cycle 16), which is conservative with respect to the current plan for EPU implementation in 2006 (Cycle 18).

The reduction of applicability of the PT curves EFPY values was arrived at by interpolating EFPY associated with the fluence values identified for the 5.5% uprate from WCAP-15570 to the fluence values determined for the 9.4% uprate identified in Table 6.5-1A of the EPU Licensing Report.

The basis for reducing the effective applicability of the PT curves is founded in the fact that the PT curves are generated based upon the accumulated fluence of the material and since the accumulated fluence for 28 EFPY in a 5.5% uprated condition is nearly the same as the accumulated fluence for 27.58 EFPY in a 9.4% uprated condition the associated PT curves would be equivalent for the identified fluence.

J.4 <u>Question</u>: (Applicable to EPU)

The staff has determined that FENOC has submitted the uprated PT limit curves to the NRC (for information only) as part of the BVPS-1 and 2 8% EPU. The NRC staff has also determined that license Amendments Nos. 256 to the BVPS-1 Technical Specifications (TS) and 138 to the BVPS-2 TS granted FENOC the right to relocate the BVPS-1 and 2 PT limit curves into a Pressure Temperature Limits Report (PTLR). TS 6.9.6, "Pressure and Temperature Limits Report (PTLR)" provides the administrative TS requirements for making changes to the BVPS-1 and 2 PT limit curves and for implementing the BVPS-1 and 2 PTLR. Paragraph c. of TS 6.9.6 requires the following:

> **The PTLR shall be provided to the NRC upon issuance for each reactor fluence period and for any revision or supplement thereto.**

Clarify how submission of only the uprated, revised PT limit curves for BVPS-1 and 2 satisfies the intent of TS 6.9.6.c, as opposed to submitting the entire PTLR. Otherwise, submit the uprated, PTLR for BVPS-1 and 2 as part of the 8% EPU request.

Response:

Providing markups of the PTLR heat/cooldown curves in the EPU LAR submittal was not meant to imply that the NRC would not be provided with a complete revision of each unit's PTLR when they are issued. The markups were provided for information only and were to show how EFPY for each unit would change for the EPU power level increase. The change in EFPY for BVPS-1 is a reduction of 1 year to conservatively account for the expected increase in vessel fluence associated with the EPU, which assumed EPU implementation as early as the spring of 2003. The change in EFPY for BVPS-2 is due to the Capsule W analysis which accounts for the increased power level of the EPU.

Recently, Revision 1 of the PTLR for each BVPS unit was issued and sent to the NRC by FENOC letter L-05-063 dated March 31, 2005. BVPS-2 PTLR Revision 1 incorporated the heatup/cooldown curves from WCAP-15677, which reflects the Capsule W analysis, extends EFPY to 22, and accounts for the increased neutron fluence associated with the EPU. BVPS-1 PTLR Revision 1 consists of entirely editorial changes regarding what Technical Specifications and Licensing Requirements reference the PTLR. These editorial changes are included in BVPS-2 PTLR Revision 1. These PTLR revisions were provided to the NRC in accordance with TS 6.9.6.c.

At this time, a revised PTLR for BVPS-1 can not be issued before the EPU submittal is approved and an actual increase in power and implementation date are known, since the unit will operate at the existing power level for some time.

Since BVPS-2 PTLR Revision 1 accounts for the increased power level, a revision following approval of the EPU submittal is not necessary.

A PTLR submittal of only the changes to the heatup/cooldown curves was never intended by FENOC. FENOC will comply with TS 6.9.6.c and provide a complete PTLR revision to the NRC upon issuance, regardless of the extent of the changes.

J.5 Question: (Applicable to EPU)

In Section 4.1.2 of Enclosure 2 of the EPU Licensing Report for BVPS-1 and 2, FENOC has referenced the following surveillance capsule reports that are applicable to the BVPS-1 and 2 RV assessments (i.e., PTS, USE, and PT limits): (1) WCAP-15771, Revision 0, *Analysis of Capsule Y from Beaver Valley Unit 1 Reactor Vessel Radiation Surveillance Program* (November 2000), and (2) WCAP 15675, Revision 0, *Analysis of Capsule W from FirstEnergy Nuclear Operating Company Beaver Valley Unit 2 Reactor Vessel Radiation Surveillance Program* (August 2001). The NRC staff has calculated the following average Copper (Cu) and Nickel (Ni) Weight-percent (Wt.-%) values for the BVSP-1 and 2 surveillance plate and weld materials, as based on taking an average of the Wt.-% Cu and Ni values reported in Topical Report Nos. WCAP-15571 and WCAP-15675:

BVPS-1 (WCAP-15771, Revision 0)

	Surveillance Plate Heat No. C6317-1	**Surveillance Weld Heat No. 305424**
Wt.-% Cu:	**0.205 (average)**	**0.234 (average)**
Wt.-% Ni:	**0.534 (average)**	**0.618 (average)**

BVPS-2 (WCAP-15675, Revision 0)

	Surveillance Plate Heat No. C0544-2	**Surveillance Weld Heat No. 83642**
Wt.-% Cu:	**0.050 (average)**	**0.080 (average)**
Wt.-% Ni:	**0.560 (average)**	**0.070 (average)**

The NRC staff requests confirmation whether or not these average Wt.-% Cu and Ni values are valid. State what the Wt.-% Cu and Ni values are for the surveillance plate and weld materials that are within the scope of the BVSP-1 and 2 Reactor Vessel Radiation

Surveillance Programs (include applicable surveillance material heat numbers and associated RV plate/weld component ID numbers). Provide a reference to the pedigree of chemistry assays/tests used in the Cu and Ni Wt.% value determinations for these surveillance capsule materials.

Response:

For BVPS-1, the valid best estimate (average) Cu & Ni weight percent values were calculated in Tables 4-7, 8 & 9 of WCAP-15570. This report states the basis for the weld heat 305424 is Combustion Engineering (CE) Report NSPD-1039 with exception to the three additional weld chemistry data points obtained from Capsule Y (WCAP-15571). The CE calculation was reproduced with the additional points. As for the plate (Heat C6317-1), one additional data point was considered from the Capsule Y Report (WCAP-15571). Thus, the plate and weld valid best estimate (average) Cu and Ni values were updated. The heat numbers, pedigree, etc. are all presented in WCAP-15570 and CE Report NSPD-1039.

For BVPS-2, the valid best estimate (average) Cu and Ni weight percent values were documented in WCAP-15677. The weld metal (83642) calculation was again obtained from CE Report NSPD-1039. Note that for the plate (Heat C0544-2), RVID2 has a Cu/Ni value of 0.06/0.57, which is the same reported in WCAP-15677 and that used in the EPU evaluation. The 0.05/0.56 values in WCAP-15675 are only one data point for that plate material. There are actually 3 data points for this plate (See WCAP-15677).

J.6 <u>Question</u>: (Applicable to EPU)

In Section 4.1.2 of Enclosure 2 of the EPU Licensing Report for BVPS-1 and 2, FENOC states that the following topical reports contain the latest uprated PTS assessments for BVPS-1 and 2: (1) WCAP-15569, Revision 0, *Evaluation of Pressurized Thermal Shock for Beaver Valley Unit 1* (November 2000), and (2) WCAP-15676, *Evaluation of Pressurized Thermal Shock for Beaver Valley Unit 2* (August 2001). The NRC staff requests that FENOC provide its technical bases for changing the previously reported Wt.-% Cu and Ni values for the following BVSP-1 and 2 RV beltline plate and weld materials:

BVSP-1:

- **Lower Shell Plate B6903-1 (Heat No. C6317-1): State the basis for increasing the Wt.-% Cu value from 0.200 to 0.210. NOTE: This is the limiting material in the BVSP-1 RV.**

BVSP-2:

- **Intermediate Shell Plate B9004-1 (Heat No. C0544-1): State the basis for decreasing the Wt.-% Cu value from 0.070 to 0.065 and increasing the Wt.-% Ni value from 0.530 to 0.550.**

- **Intermediate Shell Plate B9004-2 (Heat No. C0544-2): State the basis for decreasing the Wt.-% Cu value from 0.160 to 0.060. NOTE: This material in represented in the BVPS-2 Reactor Vessel Radiation Surveillance Program.**

Response:

For BVPS-1, the Lower Shell Plate B6903-1 has an additional test performed under Capsule Y (WCAP-15571). This additional test produced a Cu /Ni result of 0.21/0.53. Thus, when averaging with the original Certified Mill Test Report (CMTR) Cu/Ni data point of 0.20/0.54, it produced a best estimate average of 0.205/0.535. These values are conservatively rounded to 0.21/0.54.

For BVPS-2, Intermediate Shell Plate B9004-1, the basis is in WCAP-15677 (Table 4-7). It's the average of 2 Cu & Ni data points (Cu: 0.07, 0.06 and Ni: 0.53, 0.57), which produces a best estimate average of 0.065 Cu and 0.55 Ni.

For BVPS-2, Intermediate Shell Plate B9004-2, the Cu value should never have been 0.16. RVID2 has 0.06 Cu and the analysis in WCAP-15677 and what was used in the EPU analysis was also 0.06. As seen in WCAP-15677, there are only 3 data points for this plate, none of which exceed 0.07 for weight percent Cu.

J.7 <u>Question</u>: (Applicable to EPU)

In Section 4.1.2 of Enclosure 2 of the BVPS-1 and 2 EPU Licensing Report, FENOC states that the USE assessments for the RV beltline plate and weld components were reassessed using the uprated EPU neutron fluences and that the uprated USE values and assessments for the BVPS-1 materials were included in WCAP-15571, Revision 0, *Analysis of Capsule Y from Beaver Valley Unit 1 Reactor Vessel Radiation Surveillance Program* (November 2000) and for BVPS-2 in WCAP 15675, Revision 0, *Analysis of Capsule W from FirstEnergy Nuclear Operating Company Beaver Valley Unit 2 Reactor Vessel Radiation Surveillance Program* (August 2001). However, upon review of these WCAPs, the NRC staff has determined that the WCAPs provided updated USE assessments only for those RV beltline plate and weld materials that are represented in the BVSP-1 and 2 Reactor Vessel Radiation Surveillance Programs and did not provide a complete set of USE assessments for the RV beltline plate and weld components, as evaluated for uprated neutron fluences for the components at the 1/4T locations of the RVs.

(A) If WCAP-15571, Revision 0, and WCAP-15675, Revision 0, have been referenced in error and the uprated USE assessments are provided in other WCAPs or topical reports, reference which WCAPs/topical reports contain the complete sets of uprated EPU USE assessments for the BVPS-1 and 2 RV beltline plate and weld components (as evaluated in accordance with the uprated neutron fluences for the components at the 1/4T location of the RVs), and indicate whether the reports have been submitted to either the NRC's Document Control Desk or into ADAMS.

(B) Otherwise, provide the uprated EPU USE assessment calculations and results for all BVPS-1 and 2 RV plate, forging, and weld components that will accumulate an updated, end-of-current operating license (EOL) neutron fluence in excess $1X10^{17}$ n/cm^2 (i.e., neutron fluence values based on neutron energies E $\geq$ 1.0 MeV, as assessed for the 1/4T location of the RVs).

Account for the impacts of FENOC's response to RAI 4.1.2-1 on the response to this RAI, as determined to be relevant to the uprated USE values for the BVPS-1 and 2 RV beltine base-metal and weld materials.

Response:

The BVPS-1 and BVPS-2 EPU USE values for the full 9.4% total power uprate are presented in Table 11.a and 11.b, respectively. The 1/4T neutron fluences for BVPS-1 were re-calculated for the full 9.4% uprate. A review of Figure 2 of Regulatory Guide 1.99, Rev.2, showed that the small change in 1/4T neutron fluence would only change the BVPS-1 EOL USE for any material by less than 1%. Consequently, it was concluded that the USE values calculated for the current BVPS-1 Capsule Y (WCAP-15571) analysis apply for the full 9.4% uprate. The USE values calculated for the current BVPS-2 Capsule W (WCAP-15675) analysis already consider and apply the full 9.4% uprate.

TABLE 11.a
BVPS-1: Predicted End-of-License (27.44 EFPY) USE Calculations for all the Beltline Region Materials

Material	Weight % of Cu	1/4T EOL Fluence (10^{19} n/cm^2)	Unirradiated USE (ft-lb)	Projected USE Decrease[(b)] (%)	Projected EOL USE (ft-lb)
Intermediate Shell Plate B6607-1	0.14	2.21	94	28	68
Intermediate Shell Plate B6607-2	0.14	2.21	83	28	60
Lower Shell Plate B6903-1 [(a)]	0.21	2.21	83	33[(a)]	56
Lower Shell Plate B7203-2	0.14	2.21	85	28	61
Lower Shell Longitudinal Weld 20-714A/B (Heat 305414)[(a)]	0.34	0.441	>100	38[(a)]	>62
Intermediate to Lower Shell Circ. Weld 11-714 (Heat 90136)[(a)]	0.27	2.20	144	35[(a)]	84
Intermediate Shell Longitudinal Weld 19-714A/B (Heat 305424)[(a)]	0.27	0.441	112	25[(a)]	84

Notes:
(a) The % decrease is based on Beaver Valley Unit 1, St. Lucie 1 or Ft. Calhoun Surveillance Data surveillance program results.
(b) Values are deduced from Figure 6.3-2: Regulatory Guide 1.99, Revision 2, Predicted Decrease in Upper Shelf Energy as a Function of Copper and Fluence.

TABLE 11.b
BVPS-2: Predicted End-of-License (32 EFPY) USE Calculations for all the Beltline Region Materials

Material	Weight % of Cu	1/4T EOL Fluence (10^{19} n/cm^2)	Unirradiated USE (ft-lb)	Projected USE Decrease[(b)] (%)	Projected EOL USE (ft-lb)
Intermediate Shell Plate B9004-1	0.065	2.4	83	23	64
Intermediate Shell Plate B9004-2[(a)]	0.06	2.4	79	10[(a)]	71
Lower Shell Plate B9005-1	0.08	2.4	82	23	63
Lower Shell Plate B9005-2	0.07	2.4	78	23	60
Lower Shell Longitudinal Weld 101-142A/B (Heat 83642)[(a)]	0.046	2.4	145	5.4[(a)]	137
Intermediate to Lower Shell Circ. Weld 101-171 (Heat 83642)[(a)]	0.046	2.4	145	5.4[(a)]	137
Intermediate Shell Longitudinal Weld 101-124A/B (Heat 83642)[(a)]	0.046	2.4	145	5.4[(a)]	137

Notes:

(a) The % decrease is based on Beaver Valley Unit 2 Surveillance Data surveillance program results.

(b) Values are deduced from Figure 6.3-2: Regulatory Guide 1.99, Revision 2, Predicted Decrease in Upper Shelf Energy as a Function of Copper and Fluence.

J.8 Question: (Applicable to EPU)

In Section 4.1.2 of the BVPS-1 and 2 EPU Licensing Report, FENOC states that the most recent RV surveillance capsule withdrawal schedule for BVPS-1 is given in Table 7-1 of WCAP-15571, Revision 0 (Capsule Y report, November 2000) and that the most recent RV surveillance capsule withdrawal schedule for BVPS-2 is given in Table 7-1 of WCAP-15675, Revision 0 (Capsule W Report, August 2001). Part 50, Appendix H, Section III.B.3 of 10 CFR, requires that proposed changes to RV surveillance capsule withdrawal schedules be submitted for NRC review and approval. The NRC staff makes the following requests:

(1) For those capsules that remain in the BVPS-1 and 2 reactors and are proposed for capsule removal during either the current operating term or anticipated extended period of operation, clarify whether the projected neutron fluence values associated with the anticipated times of withdrawal account for the impacts of the uprated 8% power uprate on projected neutron fluence values, and if so, how. If the projected fluence values in the tables do account for the impact of the 8% power uprate, clarify whether the proposed withdrawal schedules are intended to be used by FENOC as the basis for the future surveillance capsule withdrawals from the BVPS-1 and 2 RVs, as performed in accordance with the BVPS-1 and 2 Reactor Vessel Radiation Surveillance Programs, and whether these proposed withdrawal schedules have been reviewed and approved by the NRC staff, as required pursuant to Section III.B.3 of 10 CFR Part 50, Appendix H. Otherwise, if unapproved, clarify whether FENOC is requesting the NRC staff's approval of the withdrawal schedules, pursuant to the review and approval requirements stated in the previous sentence.

[Note: The NRC staff needs to emphasize that Section III.B.3 of 10 CFR Part 50, Appendix H, *Reactor Vessel Material Surveillance Program Requirements,* requires that proposed RV surveillance capsule withdrawal schedules be submitted to the NRC with a technical justification and be approved prior to implementation. The NRC staff also needs to emphasize that, in Commission Memorandum and Order, CLI-96-013, the Commission made a decision that changes to RV materials surveillance program withdrawal schedules would not have be processed through the 10 CFR 50.90 license amendment process if the changes were verified as being in conformance with the withdrawal schedule provisions of American Society for Testing & Materials (ASTM) Standard Practice E185. Thus, if FENOC is requesting the NRC staff's approval of the withdrawal schedules in Tables 7-1 of Topical Reports WCAP-15571, Revision 0, and WCAP-15675, Revision 0, and is requesting review and approval through the 10 CFR Part 50, Appendix H process, the NRC staff will place its review outside the scope of 10 CFR 50.90, 50.91, and 50.92 licensing action provisions if the NRC staff determines that the proposed withdrawal schedule changes are in conformance with the surveillance capsule withdrawal schedule provisions of ASTM Standard Practice E185-82. Under these circumstances the changes would not be subject to licensing action "Hearing" provisions, as would be consistent with the Commission's decision in CLI-96-013.]

(2) **If the projected fluence values in the Table 7-1 of WCAP-15571 and Table 7-1 of WCAP-15675 do not account for the impact of the uprate 8% power uprate, clarify how the uprated 8% EPU will impact proposed withdrawal schedules for the surveillance capsules, including projected times of withdrawal (in EFPY) and associated projected neutron fluence values for the withdrawals. If FENOC determines that further changes to the surveillance capsule withdrawal schedules described in Table 7-1 of WCAP-15571 and Table 7-1 of WCAP-15675 are necessary as a result of this RAI, clarify whether and when FENOC intends to request the NRC staff's review and approval of the proposed changes, as required under 10 CFR Part 50, Appendix H, Section III.B.3.**

Response:

(1) The impact of the 9.4% total power increase with implementation in 2003 on RV surveillance capsule withdrawal schedules is addressed in Section 4.1.2 of the EPU Licensing Report.

Since the schedules presented in the EPU Licensing Report were developed in accordance with the provisions of ASTM E185-82 and using the guidance provided in the Commission memorandum and Order, CLI-96-013, the submitted surveillance schedules would not be subject to licensing action. FENOC will continue to monitor the fluence and maintain the surveillance program for the vessels in accordance with ASTM E185-82.

(2) Refer to the response provided in the first part of this question. FENOC will comply with ASTM E185-82 and there is no need for regulatory approval.

J.9 <u>Question</u>: (Applicable to EPU)

NRC Review Standard NRR-RS-001, Revision 0, *Review Standard for Extended Power Uprates (December 2002)*, provides the staff's standard review plan for evaluation license amendment requests for increasing power above 5-percent of the current core thermal power rated for a U.S. light-water reactor. Note 1 in Matrix 1 of Section 2.1 of NRR-RS-001, Revision 0, provides the following guidance for managing age-related degradation mechanisms in pressurized-water reactor (PWR) RV internals components:

> **In addition to the SRP, guidance on the neutron irradiation-related threshold for inspection for irradiation-assisted stress-corrosion cracking for BWRs is in BWRVIP-26 and for PWRs in BAW-2248 for E>1 MeV and in WCAP-14577 for E>0.1 MeV. For intergranular stress-corrosion cracking and stress-corrosion cracking in BWRs, review criteria and review guidance is contained in BWRVIP reports and associated staff safety evaluations. For thermal and neutron embrittlement of cast austenitic stainless steel, stress-corrosion cracking, and void swelling, licensees will need to provide plant-specific degradation management programs or participate in industry programs to investigate degradation effects and determine appropriate management programs.**

WCAP14577, Rev. 1-A, established a threshold neutron fluence level of $1x10^{21}$ n/cm^2 (E > 0.1 MeV) for the initiation of irradiation assisted stress corrosion cracking (IASCC) in Westinghouse-designed RV internals. The NRC staff has used $5x10^{20}$ n/cm^2 (E > 1.0 MeV) as its threshold for the initiation of IASCC, loss of fracture toughness induced by neutron irradiation embrittlement, and void swelling in stainless steel or nickel-based alloy RV internal components. Recent operating experience with cracking of steam dryers at the Quad Cities Nuclear Plant has demonstrated that cracking of boiling-water reactor (BWR) RV internal components may occur under BWR constant pressure power uprated conditions even after a short amount of time has elapsed at the uprated power conditions. The NRC staff is concerned that this may also become an issue for the extended power uprates that are proposed for PWR-designed facilities.

FENOC's EPU license amendment application did not indicate what the neutron fluence values (E > 0.1 MeV) will be for each RV internal components under the uprated 8-percent power conditions or what the limiting uprated neutron fluence value (E > 0.1 MeV) will be for the BVPS-1 and 2 RV internal components if the components are grouped collectively as a commodity group. FENOC's EPU license amendment application also did not provide any indication as to what measures FENOC would implement to conform to or meet the issues raised in Footnote 1 of Matrix 1 to Review Standard NRR-RS-001. With respect to evaluating the impact of the proposed EPU on the RV internal components at BVPS-1 and 2:

(1) State what the specific uprated neutron fluence values (E > 0.1 MeV) will be for each RV internal component at BVPS-1 and 2, as impacted by the uprated 8% power conditions, or what the limiting uprated neutron fluence will be for each unit's RV internal components if the RV internal components are grouped collectively as a commodity group.

(2) If the projected neutron fluence values for the RV internals are projected to exceed the threshold established by Westinghouse Electric in WCAP-14577, the NRC staff requests that FENOC either propose and identify an inspection program that will be utilized to manage the aging effects discussed in the paragraph above, or else provide a commitment to participate in and implement the EPRI MRP's research initiatives on age-related degradation of RV internal components and to submit the inspection plan for the BVPS-1 and 2 RV internals for NRC staff review and approval. If FENOC determines that aging management of the RV internals is necessary for the uprated power conditions and an inspection program is proposed as the basis for aging management, discuss the scope of the program and include specific details on which RV internal components and sample size of components will be inspected. Also discuss which aging effects will be monitored, which inspection methods and inspection qualifications will be used for the examinations, the frequency of examinations used for the inspections, what acceptance criteria will be used to evaluate any recordable and relevant flaw indications or evidence of distortion if void swelling is identified as an aging effect of concern, and the schedule for program implementation.

Response:

(1) The reactor vessel internals components are currently addressed as a commodity group when addressing the neutron fluence effects. All the Reactor Internals components in a PWR are considered to have been exposed to a fluence in excess of $1x10^{21}$ n/cm^2 (E>0.1 MeV) after the first several fuel cycles.

(2) FENOC recognizes that all the Reactor Internals components are considered to have been exposed to fluences in excess of the threshold value identified in WCAP-14577 after the first few cycles of operation. In response to this understanding, FENOC has been active on the Electric Power Research Institute (EPRI) Materials Reliability Project (MRP) Issue Task Group (ITG) addressing the age-related degradation effects on reactor internals components for more than five (5) years and is committed to continued participation.

FENOC is and will continue to monitor the Industry inspection findings and Operating Experience, as part of the general assessment of any need to increase the monitoring and inspection activities above the current ASME Section XI program. Since several other plants of similar design and configuration have been operating at extended power levels for several years and will experience fluences comparable to those projected at BVPS prior to BVPS reaching those fluence levels, these plants will provide insight as to the need for any increased actions during the current license life.

The EPRI MRP committee is actively working with plants with license renewal commitments to submit inspection plans and procedures in the 2007 time frame. These plans and procedures are being developed and issued by the EPRI MRP committee for the management of the aging mechanisms during the license renewal period. The EPRI MRP committee will issue these documents through the protocols developed under NEI 03-08. Since FENOC is committed to the NEI 03-08 initiative, FENOC will follow the guidance issued in accordance with the NEI 03-08 implementation protocol.

K. Material Properties of Components

K.1 Question: (Applicable to EPU)

Please provide a brief outline of your Alloy 600 management program intended to manage and identify mitigative actions to address primary-water stress corrosion cracking (PWSCC) in Alloy 82/182 weld locations in the RCS. Has any mitigative action taken place or is planned to be taken to manage PWSCC in the susceptible material?

Response:

The BVPS Alloy 600 Program is controlled by two administrative procedures, one at the FENOC corporate level and the other a site implementation procedure. The program defines the approach and processes that FENOC will use to maintain the integrity and operability of each Alloy 600/82/182 and Alloy 690/52/152 component for the remaining life of the plant. The program applies to all Alloy 600 and 690 components in the primary system, with the exception of the steam generator tubing and internals, which are addressed by the Steam Generator Management Program and its required degradation assessment.

The Alloy 600/690 Management Program is maintained as a core engineering program, with both a Site and Fleet Program Owner. The program procedures clearly define the cross-disciplinary roles and responsibilities for individuals and departments responsible for successful implementation of the program. Program changes and activities are elevated to the appropriate level of management to ensure ownership and alignment on Alloy 600 related issues.

The Alloy 600/690 Management Program begins by ranking all of the applicable components for susceptibility to PWSCC. This analysis was completed, taking into account time, temperature, operating and residual stress, and fabrication process. The resulting susceptibility index identifies each component's PWSCC susceptibility in relation to all the others. This index establishes the basis for the site inspection plan.

The Alloy 600 inspection plan is maintained in the controlled site procedure. The plan defines the frequency and types of inspections to be performed, on a refueling outage basis. It reflects current NRC requirements and commitments and NEI-03-08 "Mandatory" and "Needed" industry guidance documents recommending inspections of Alloy 600/82/182 components. The program owner coordinates the performance of the program-required inspections with the site NDE and ISI personnel each refueling outage.

Contingency repair plans are developed and maintained for susceptible components to a level commensurate with the probability and consequences of cracking and/or leakage. Repairs or replacements performed using Alloy 690/52/152 materials remain within the scope of the program.

The overall objective of the Alloy 600/690 Management Program at BVPS is to mitigate or replace susceptible Alloy 600/82/182 components in the primary system at the earliest opportunity, wherever possible. Mitigation, replacement, and preemptive repair options are considered for implementation based on the probability and consequences of failure of a particular component. A detailed risk-economic analysis was performed to determine the long-term course of action for each Alloy 600 component, given the probability of cracking/leakage and potential impact to plant safety and reliability. The results of this evaluation are currently being incorporated into the site's long-range plan.

Mitigative measures already taken or in progress at BVPS include:

- BVPS-1, Zinc Addition (Began in 2002 for exposure control, but may have PWSCC benefit for wetted components. Average RCS Zn (natural) = ~35 ppb)
- BVPS-1, reactor pressure vessel (RPV) head replacement (Spring 2006)

Future mitigation and repair options are currently being evaluated and prioritized. The high priority locations for possible mitigation and/or repair include the pressurizer spray (BVPS-1/2), safety (BVPS-1/2), relief (BVPS-1/2), and surge (BVPS-2) nozzles, and the RV hot leg nozzles (BVPS-2). Future RPV head replacement is currently being evaluated for BVPS-2.

K.2 <u>Question</u>: **(Applicable to EPU)**

Please summarize the results of volumetric examinations performed during the past inservice inspection of all Alloy 82/182 welds in the RCS. The ASME Code, Section XI, allows flaws to be left in service after a proper evaluation of the flaws is performed in accordance with Subsection IWB-3600. Indicate whether such flaws exist in any of the welds analyzed for leak-before-break (LBB) approval.

Response:

Volumetric examinations performed on BVPS-1 and BVPS-2 alloy 82/182 RCS welds are summarized in Table 12. These examinations were performed with ultrasonic testing (UT) in accordance with approved NDE procedures typical of the vintage of the examinations. To date, no flaws have been detected in any of the welds that exceeded the size of allowable flaws defined in Subsection IWB-3500 or required analytical evaluation in accordance with Subsection IWB-3600.

For BVPS-1, Leak-Before-Break (LBB) methodology is used for the reactor coolant system (RCS) main coolant loop and pressurizer surge line piping. For BVPS-2, LBB methodology is used for the reactor coolant system main coolant loop and pressurizer surge line piping as well as branch line piping greater than 4 inch diameter. The branch line piping is detailed in Table 3.6B-4 of the BVPS-2 UFSAR and is fabricated of SA376 type 316 stainless steel.

As shown in Table 12, no flaws have been detected in alloy 82/182 welds used in LBB applications for BVPS-1 and BVPS-2. BVPS-1 has no 82/182 welds in the RCS main coolant loop and pressurizer surge line. BVPS-2 does have 82/182 welds in the RCS main coolant loop, pressurizer surge line, and pressurizer safety valve and power operated relief valve (PORV) lines, but volumetric examinations of these welds show that there are no flaws.

Table 12			
BVPS-1 Alloy 82/182 RCS Volumetric Examination History Summary			
Configuration	**Weld Identification**	**Volumetric Exam Dates**	**IWB-3600 Evaluation Required?**
4" Pressurizer Spray Line Nozzle to safe end weld	RC-72-7-E-01	1978, 1986, 1989, 1997	No
6" Pressurizer Safety Valve Nozzle to safe end weld	RC-99-1-E-03	1983, 1993, 1997	No
6" Pressurizer Safety Valve Nozzle to safe end weld	RC-97-1-E-01	1983, 1996, 1997	No
6" Pressurizer Safety Valve Nozzle to safe end weld	RC-98-1-E-02	1983, 1989, 1996, 1997	No
6" Pressurizer PORV Nozzle to safe end weld	RC-104-1-E-01	1988, 1996, 1997	No
BVPS-2 Alloy 82/182 RCS Volumetric Examination History Summary			
Configuration	**Weld Identification**	**Volumetric Exam Dates**	**IWB-3600 Evaluation Required?**
Reactor A Loop Outlet nozzle to safe end weld	2RCS-REV21- N-28	1987, 1989, 1996	No
Reactor A Loop Inlet nozzle to safe end weld	2RCS-REV21- N-27	1987, 1996	No
Reactor B Loop Outlet nozzle to safe end weld	2RCS-REV21- N-26	1987, 1989, 1996	No
Reactor B Loop Inlet nozzle to safe end weld	2RCS-REV21- N-25	1987, 1996	No
Reactor C Loop Outlet nozzle to safe end weld	2RCS-REV21- N-24	1987, 1989, 1996	No
Reactor C Loop Inlet nozzle to safe end weld	2RCS-REV21- N-23	1987, 1996	No
4" Pressurizer Spray Line Nozzle to safe end weld	2RCS-PRE21-202Z	1987, 1989, 1996, 1999	No
14" Pressurizer Surge Line Nozzle to safe end weld	2RCS-PRE21-84Z	1987, 1989, 1999	No
6" Pressurizer Safety Valve Nozzle to safe end weld	2RCS-PRE21-103C	1987, 1992, 1996	No
6" Pressurizer Safety Valve Nozzle to safe end weld	2RCS-PRE21-102B	1987, 1992, 1996	No
6" Pressurizer Safety Valve Nozzle to safe end weld	2RCS-PRE21-101A	1987, 1992, 1996	No
6" Pressurizer PORV Nozzle to safe end weld	2RCS-PRE21-107Z	1987, 1996	No

K.3 <u>Question</u>: **(Applicable to EPU)**

Discuss the material properties of the RCS at EPU conditions and how these new properties have been applied to, and affect, your LBB evaluations.

Response:

For the primary loop piping, the maximum normal operating temperatures change for EPU conditions. Thus, new tensile material properties (i.e., average yield strength, minimum yield strength, minimum ultimate strength, and modulus of elasticity) were calculated using the maximum normal operating temperatures for EPU conditions (i.e., hot leg temperature of 617°F and cold leg temperature of 543.1°F). The maximum normal operating temperature of the cold leg (i.e., 543.1°F) was also used conservatively for the cross-over leg piping.

For the surge line piping, the various operating temperatures used in the LBB analysis do not change for EPU conditions. Thus, the calculation of new material properties was not required for the surge line piping.

These new material properties were then used in the LBB evaluations which were performed consistent with the NRC approved LBB methodology. The results of the evaluations show that all the LBB recommended margins (Reference 1, identified below) are satisfied at the EPU conditions. It is therefore concluded that the dynamic effects of reactor coolant system primary loop pipe breaks and the pressurizer surge line pipe breaks do not need to be included in the structural design basis for BVPS-1 and BVPS-2 at the EPU conditions.

Reference:

1. Standard Review Plan: Public Comments Solicited; Leak-Before-break Evaluation Procedures; Federal Register/Vol. 52, No. 167/Friday August 28, 1987/ Notices, pp. 32626-32633.

L. Operating Procedures

L.1 Question: (Applicable to EPU)

In Sections 10.15 and 10.9 of the EPU Licensing Report, it is stated that the EPU will require revision of operating procedures, training materials and the plant simulator. Describe the changes that will be made to the operating procedures and training materials.

Response:

Implementation of EPU will require revisions to the operating procedures as well as changes to training materials. These changes include:

- Operation at higher Rated Thermal Power (RTP) level (i.e., revised RCS temperatures, revised steam and feed flows, temperatures, and pressures, revised feedwater and heater drain flow control valve positions, and revised electrical loads)
- Revised Reactor Trip and engineered safety features (ESF) actuation setpoints
- Revised operating band for SI accumulator pressure and level
- Revised primary plant water storage tank (PPWST) level setpoint
- Revised high pressure (HP) Turbine 1st stage pressure setpoint and operating pressure
- Revised safety injection flows used in safety analysis (revised minimum pump curve)
- Revised auxiliary feedwater flows used in safety analysis (revised minimum pump curve)
- Revised maximum refueling water storage tank (RWST) temperature
- Elimination of boron injection tank (BIT) Technical Specification (BVPS-1)
- Revised decay heat curve
- Revised main generator capability curve and VAR loading
- Revise RCS pressurizer and SG safety valve setpoint tolerance
- Revised primary and secondary activity Technical Specifications
- Revised RCP seal injection Technical Specification surveillance

Setpoints that are mentioned in the operating procedures, this includes the emergency operating procedures, the abnormal operating procedures and the severe accident management guidelines, will be changed to the new uprate values. BVPS-1 procedures that contain steps that fulfill surveillances for the BIT Technical Specification will be deleted or revised accordingly to reflect the elimination of this Technical Specification.

All the operating procedures affected by EPU LAR will be revised using the existing procedure revision processes, and issued for use at the time of implementation.

The Engineering Change Process (ECP) requires the Training Department to perform an evaluation per the systematic approach to training (SAT) for all affected plant modifications and procedure changes. All of the affected changes for EPU will be implemented by an ECP. If the SAT evaluation (training needs analysis) determines that training is to be performed, then the applicable training material lesson plans will be revised to address the plant modifications and procedural changes. Then, as determined by the Operations Training Committee, the designated licensed and non-licensed personnel will complete training on the applicable changes prior to startup at the modified conditions.

L.2 <u>Question</u>: (Applicable to EPU)

Describe the changes which will be made to the plant simulator. When will the changes to the plant simulator be implemented? To which ANSI standard will simulator fidelity and performance be measured?

Response:

Each of the BVPS simulators was previously upgraded for the Reactor Coolant System, Steam Generators and Reactor Core models. Changes to the plant simulators associated with power uprate conditions will be implemented prior to EPU implementation for each unit.

Simulator changes include:

- Revised setpoints and scaling for Reactor Trip and engineered safety features (ESF) actuation's
- Revised control system settings including pressurizer level, RCS temperature, rod control, and turbine control
- Revised containment pressure indicator scaling and meter readout (panel hardware and software)
- Revised steam generator model geometry (Unit 1 only) including new level control and actuation setpoints
- Revised tank and system level, pressure and temperature including RWST, PPWST, and SI accumulators
- Revised system configurations for Quench Spray (panel hardware and software) and BIT (Unit 1 simulator only)
- Updated simulator Initial Condition (IC) sets
- Primary system and Balance of Plant (BOP) tuning to satisfy ANSI/ANS-3.5 requirements of +/- 2% for critical parameters and +/- 10% for non-critical parameters

The BVPS-1 simulator steam generator model is being revised for the RSG configuration, and associated changes to the BVPS-1 simulator will be implemented by the spring of 2006 (1R17 refueling outage). Changes that affect the simulator will be implemented through the plant approved change process. The setpoint and scaling changes for BVPS-1 will be performed for the EPU, RSG and containment conversion (CC) changes to support emergency operating procedure (EOP) validations.

BVPS-2 scaling and setpoint changes for EPU and CC will also be performed to support EOP validations prior to plant implementation.

Both BVPS-1 and BVPS-2 simulators will be bench-marked with the best estimate engineering models for the 10 ANSI/ANS-3.5 Appendix B transients and will have an initial 100% steady state comparison to the predicted values followed by a final comparison to actual plant values at 100% power. Both BVPS simulators are certified to the ANSI/ANS-3.5-1985 standard.

L.3 Question: (Applicable to EPU)

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.

Response:

The following has been identified as a new operator action relating to the emergency operating procedures as the result of the proposed Extended Power Uprate:

- Control Room purge after a steam generator tube rupture (SGTR) – within 8 hours following termination of the environmental release for a SGTR, the Control Room is purged for 30 minutes at 16,200 cfm.

The following has been identified as a change to a current operator action relating to the emergency operating procedures as the result of the proposed Extended Power Uprate:

- Control Room purge after a MSLB – following termination of the environmental release for a MSLB, the Control Room is purged for 30 minutes at 16,200 cfm. Current operator action is a purge within 8 hours at a higher flowrate.

The following is a summary of the operator action times that were affected by the EPU analyses:

- initiation time for switchover to hot leg recirculation
- termination time for uncontrolled boron dilution
- termination time for isolation of auxiliary feedwater to faulted steam generator
- termination time of auxiliary feedwater to prevent SG overfill
- termination time of high head flow to prevent pressurizer overfill
- time to isolate steam release from faulted SG following SG tube rupture
- time at which to purge Control Room following termination of radioactive steam release

The plant Engineering Change Process will be followed to make the necessary changes to address the plant modifications, procedural changes and operator action times. The process requires that the Training Department perform an evaluation per the systematic approach to training (SAT) for all affected plant changes. If the SAT evaluation (training needs analysis) evaluation determines that additional training is to be performed, then the applicable training material lesson plans will be revised to address the plant changes.

L.4 Question: (Applicable to EPU)

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 be informed of the changes? Describe any controls, displays, alarms that will be upgraded from analog to digital as a result of the proposed EPU and how will operators be tested to determine proficiency?

Response:

For the EPU, instrumentation will be re-normalized such that 100% indications of RTP will remain at 100% RTP. Operator interfaces for control room controls, displays, and alarms will be re-normalized such that there is no change in operator actions for normalized protection, control, displays, and alarms. BVPS-1 does not use zone markings on any meters. Those functions being revised as a result of the EPU analyses are:

- An increase in the RWST high temperature limit to 65°F
- An increase in the Accumulator Pressure low and high limits
- An increase in the Accumulator Water Level low and high limits
- Pressurizer Water Level Program for the EPU analysis is based on the pressurizer program varying linearly such that at a Tavg of 580°F, the pressurizer level is controlled to 60% water level. The program will maintain the pressurizer level at 55% compared to the current level of 54% water level for the existing 576.2°F Tavg full power setpoint. The same program is applicable for a full power Tavg varying between cycles from 566.2°F to 580°F.
- TREF for the Steam Dump function is developed from Turbine 1st Stage pressure. With operation at EPU conditions the C7B setpoint must be reduced from 50% to support the EPU setpoint of 35% full steam flow.
- Overtemperature ΔT and Overpower ΔT protection setpoints are revised to optimize plant operations for the EPU conditions. This includes utilization of filters to reduce signal noise and align instrumentation with the analyses.
- For BVPS-2 only, the Primary Plant Demineralized Water Tank volume low alarm is revised to be consistent with the BVPS-1 volume requirements.
- For BVPS-1 only, the replacement steam generators necessitate revisions to all of the associated water level setpoints, both control and protection, alarms, Emergency Operating Procedures, and the Severe Management Accident Guidelines.

The ECP process requires that the Training Department perform an SAT evaluation for all affected plant modifications. If the SAT evaluation (training needs analysis) determines that training is to be performed, then the applicable training material lesson plans will be revised to address the plant modifications and procedural changes. Then, as determined by the Operations Training Committee, the designated licensed and non-licensed personnel will complete training on the applicable changes prior to implementation.

There are no controls, displays, alarms that will be upgraded from analog to digital as a result of the proposed EPU.

L.5 Question: (Applicable to EPU)

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

Response:

Plant process instrumentation will be normalized to the uprated power levels. The BVPS-1 safety parameter display system (SPDS) equipment is in both the control room and the emergency response facility, and the instrument spans are changing. The BVPS-2 Emergency Response Facility Computer System (ERFCS) is in both the control room and the emergency response facility, and both instrument spans and setpoints are changing. The plant Engineering Change Process will be followed to make the changes and includes operations, training, and the simulator groups when determining impacts on the changes and determining if additional training is necessary.

Planned changes to the safety parameter display systems are summarized in Table 13.

Table 13		
BVPS-1		
Description	**Before EPU**	**After EPU**
(1)Steam Generator Water Level	Low-Low Setpoint 20.1%	Low-Low Setpoint 19.6%
(1)Steam Generator Water Level	High-High Setpoint 81.2%	High-High Setpoint 89.7%
BVPS-2		
Description	**Before EPU**	**After EPU**
(2)Turbine 1st Stage Pressure span	700 psig span	1000 psig span
Turbine 1st Stage Pressure Alarm	High Alarm 580 psig	High Alarm 800 psig
Primary Plant Demineralized Water Storage Tank Alarm	310 inches	325 inches
Accumulator Pressure Alarms	Low 605 psig - High 645 psig	Low 581 psig - High 665 psig
Accumulator Level Alarms	Low 36.5% - High 60.6%	Low 6% - High 96%

(1) Replacement steam generators on BVPS-1 have impact on the safety parameter display system due to the increased narrow range steam generator water level instrument span. The display system will be re-calibrated such that the process limits match the existing patterns. Setpoints are provided for comparison, SPDS span of 144 inches is revised to 212 inches for the replacement steam generator.

(2) Estimated setpoint, PTC-6 testing of the new High Pressure Turbine will determine optimal high alarm setpoint.

Note: For both units the feedwater and main steam flow transmitters are being replaced with units capable of measuring larger d/ps. Instrument loop scaling in terms of indicated units of million pounds per hour (mpph) remains within the existing range of the displays.

M. Plant Systems

M.1 Question: (Applicable to EPU)

Please address the impacts of the proposed power uprate and the change from a sub-atmospheric to an atmospheric containment on the licensee's response to GL 96-06.

Response:

The Nuclear Regulatory Commission (NRC) issued Generic Letter (GL) 96-06 on September 30, 1996, to all holders of operating licenses for nuclear power reactors. GL 96-06 requested information from licensees related to the following three concerns:

(1) Cooling water systems serving the containment air coolers may be exposed to the hydrodynamic effects of water hammer during either a loss of coolant accident (LOCA) or a main steam line break (MSLB),

(2) Cooling water systems serving the containment air coolers may experience two-phase flow conditions during postulated LOCA and MSLB scenarios. The heat removal assumptions for design-basis accident scenarios were based on single-phase flow conditions, and

(3) Thermally induced over pressurization of isolated water-filled piping sections in containment could jeopardize the ability of accident mitigating systems to perform their safety functions and could also lead to a breach of containment integrity via bypass leakage.

The containment air coolers at BVPS are automatically shut down on a high containment pressure signal or a loss of offsite power. The coolers do not automatically start as part of the emergency diesel generator load sequence. Neither the extended power uprate (EPU) nor containment conversion (CC) credit use of the containment air coolers and the operation and procedures controlling the use of the containment air coolers are not impacted by EPU or CC. Therefore the EPU or CC does not introduce or expose the containment coolers to the hydrodynamic effects of water hammer during either a loss of coolant accident (LOCA) or a main steam line break (MSLB).

The revised containment analysis performed for the containment conversion resulted in revised containment temperature profiles following a Loss of Coolant Accident (LOCA) and Main Steam Line Break (MSLB) resulting in an increase in the peak containment air temperature following a MSLB. The containment peak pressure also increased but remained below the design pressure of the containment. The containment conversion is raising the CIB setpoint, resulting in a higher containment air temperature at the time the CIB setpoint is reached. The containment coolers operating prior to CIB are impacted by the higher containment temperature at CIB.

As a result of the revised containment temperature profile, higher containment air temperature at the time of CIB and increase in peak temperature, the thermally induced over pressurization of isolated water-filled piping sections in containment is potentially affected and was reviewed. The review considered the heat exchangers in the containment. Also evaluated were cooling water exit temperatures to ensure that the existing stress analyses are still bounding for the piping, and piping design temperature limits are not exceeded.

Evaluation of the resultant cooling coil exit temperatures for the CAR and CRDM cooling fans confirmed that they remain below the design temperature of the piping and that the fluid remained as a single phase.

The impact of the small increase in temperature (approximately 5 degrees for BVPS-1, approximately 12 degrees for BVPS-2) does not result in piping pressures or stress values exceeding the values previously evaluated and therefore remain bounding at the EPU and CC conditions.

M.2 Question: (Applicable to RSG & EPU)

Are the revised TS Bases for TS 3.7.1.2, "Auxiliary Feedwater System," and TS 3.7.7, "Control Room Habitability System," changes to the plant licensing basis? Why does EPU necessitate a change in the TS Bases for TS 3/4.7.1.2 (small-break LOCA (SBLOCA) is no longer the worst case event, and the loss of an EDG is no longer the worst-case single failure)? Is the 15-minute operator action time that is assumed to isolate the fault a change from previous assumptions?

Response:

TS Bases 3.7.1.2

The changes to TS Bases 3/4.7.1.2 result from an EPU change in applicable safety analysis assumptions which reflects a change to the licensing basis. The accident analyses were revised for EPU and as a result, the Loss of Normal Feedwater (LONF) and Feedwater Line Break (FLB) have replaced the small break LOCA as the limiting Design Basis Analysis (DBA) with respect to minimum AFW flow.

The current BVPS-1 UFSAR only credits one motor-driven pump for FLB and LONF. This is a conservative assumption since three pumps are available and required to support the TS LCO statement during power operation. However, the revised EPU FLB and LONF analysis credit two of three AFW pumps. The revised EPU analysis for the Feedwater Line Break uses the failure of the turbine driven AFW pump (which is the highest capacity AFW pump) as the worst-case single failure, rather than the loss of the EDG which would result in the loss of one motor driven AFW pump. Thus installed capacity is available such that single failure requirements are satisfied when two AFW pumps are relied upon. The flows required by LONF and FLB can be met with two AFW pumps with adequate operating margin.

The small break LOCA analysis for EPU conditions was revised to use AFW flow from only one motor driven pump, thus relaxing the previous requirement for one turbine-driven and one motor driven pump. This makes the small break LOCA analysis non-limiting.

The BVPS-1 Feedwater Line Break analysis for EPU conditions uses a 15 minute operator action time, which is a relaxation of the 10 minute operator action time reported in the TS Bases. This is not a change for BVPS-2. This change was made for BVPS-1 to be consistent with the BVPS-2 analysis. Modifications have been made at BVPS-1 such that both units now include cavitating venturis in the discharge lines for the AFW system. This modification allows for AFW to continue flowing to the intact steam generators during a feedwater line break prior to operator action to isolate the faulted steam generator.

TS Bases 3.7.7

The changes to TS Bases 3/4.7.7 result from a change to the licensing basis for both units. The TS Bases change for TS 3/4.7.7 reflects the licensing basis change of full implementation of AST, as proposed in EPU LAR 302/173. The other changes in this TS Bases section reflect assumptions in the dose consequence analyses related to post-accident maintenance of the Control Room atmosphere. BVPS has implemented AST in a phased – selective approach. The first use of AST was for the Fuel Handling Accident (FHA) and was approved by the NRC in Amendments 241 and 121. The second selective application of AST added the Loss of Coolant and Control Rod Ejection Accidents was approved by the NRC in Amendments 257 and 139.

M.3 Question: (Applicable to EPU)

Where does the existing licensing basis for TS 3/4.7.1.3 concerning the primary plant demineralized water (PPDW) storage tank specifically state that the 9-hour inventory is based on the RCPs being secured? Is this a change to the plant licensing basis? How much additional inventory is required for cooldown to RHR entry conditions (TMI Action Plan criteria)?

Response:

The existing licensing basis does not state that the 9 hour inventory is based on RCPs being secured. Clarification of the current licensing basis is provided as follows. The limiting transient with respect to PPDW storage tank inventory requirements is the loss-of-offsite power (LOOP) transient since normal condensate and feedwater systems will be unavailable while offsite power is lost. The LOOP transient results in the loss of the RCPs. The BVPS-1 licensing basis dictates that in the event of a LOOP, sufficient PPDW storage tank useable inventory must be available to bring the unit from full power to hot standby conditions, and maintain the plant at hot standby conditions for 9-hours. Therefore, there is no change to the current plant licensing basis. The Bases for TS 3/4.7.1.3 also currently states that sufficient water is available for cooldown of the Reactor Coolant System to less than 350°F. This statement regarding the cooldown capability is being deleted from the BVPS-1 TS Bases to provide consistency with the BVPS-1 safe shutdown licensing basis, which does not require cooldown, and the BVPS-2 TS Bases.

The additional inventory required to cooldown from the hot standby no-load temperature (547°F) to the Residual Heat Removal (RHR) System cut-in temperature (350°F) can be obtained from either the non-safety grade demineralized water storage tanks (e.g., turbine plant demineralized water storage tank of ~ 200,000 gallons and auxiliary demineralized water storage tank of ~ 600,000 gallons) or the safety grade service water system (via a cross connection). The amount of additional water required for cooldown to RHR entry conditions would be dependent on cooldown operations and the associated cooldown time.

For example, approximately 160,000 gallons of water would be used for an 8 hour cooldown from the no-load hot standby temperature of 547°F to the RHR entry condition temperature of 350°F that is initiated at a time of 0 hours (i.e., hot standby maintained for 0 hours) and completed at a time of 8 hours. The 8 hour cooldown time is equivalent to a cooldown rate of 25°F/hour. However, since a cooldown following a LOOP transient would be performed under natural circulation conditions, it would be performed subject to various procedural limitations on RCS cooldown and depressurization. A normal natural circulation cooldown could take approximately 30 hours and require approximately 300,000 gallons of water. The additional inventory required for cooldown to RHR entry conditions is available in the backup non-safety grade demineralized water storage tanks.

M.4 Question: (Applicable to EPU)

The Bases for TS 3/4.7.1.3 indicates that measurement uncertainty has not been included in the TS minimum volume requirement for PPDW inventory. A complete accounting of the minimum required TS PPDW volume that takes into consideration all postulated losses, line breaks, recirculation flow, and measurement uncertainty is needed. Identify and explain all instances where measurement uncertainty is not accounted for when confirming that indicated values are in accordance with the plant licensing basis.

Response:

The analytical values for useable PPDW volume is based on maintaining hot standby for nine hours. The PPDW suction piping, lube oil cooling/recirculation flow piping and all tank connections below the minimum useable level in the PPDWST are seismically qualified, and therefore, no pipe break losses or recirculation flow losses are considered. Non-seismically qualified PPDWST connections for tank overflow, additional PPDWST makeup and PPDWST purification return flow are above the level in the tank required for Technical Specification compliance.

The analytical values for required useable PPDW volume include the losses from the steam generator blowdown system until automatic signals are generated to isolate the blowdown system. The required values also include losses postulated by coincident sampling of the steam generators for up to one hour prior to sampling system isolation, when automatic sampling isolation does not occur.

Alarm setpoints and surveillance limits are established such that more conservative values than the Technical Specification limits are used to account for measurement uncertainties assuring that the required volume of useable water is available. Instrument uncertainty calculations account for temperature variations, tank tolerances, velocity effects on instrument taps, vortexing effects, unusable volume, and instrument loop uncertainties as defined in WCAP-11366. The methodology for the uncertainty calculations used for BVPS-1 and BVPS-2 was previously reviewed by the staff via Westinghouse WCAPs for BVPS-1 and BVPS-2. The WCAP reference for BVPS-1 is WCAP-11419 Rev. 2, "Westinghouse Setpoint Methodology for Protection Systems Beaver Valley Power Station – Unit 1" dated December 2000, and the WCAP for BVPS-2 is WCAP-11366 Rev. 4, "Westinghouse Setpoint Methodology for Protection Systems Beaver Valley Power Station – Unit 2" dated December 2000. Upon conclusion of this review the staff issued Amendment 239 to facility license DRP-66 and Amendment 120 to facility license NPF-73 via a July 30, 2001 letter titled, "BEAVER VALLEY POWER STATION, UNIT NOS. 1 AND 2 – REVISED IMPLEMENTATION PERIOD FOR LICENSE AMENDMENT NOS. 239 AND 120, (TAC NOS. MB0848 AND MB0849)". The words in the BVPS TS Bases for TS 3/4.7.1.3 provide guidance in the direction of the conservatism to which the instrument uncertainty is included.

N. Structural Loading Considerations

N.1 Question: (Applicable to EPU)

In Section 4.2.3.5 of the EPU Licensing Report, you stated that since application of LBB methodology has been licensed for the main coolant loop, consideration of breaks in the main coolant loop are not required for structural evaluations. The next limiting breaks to be considered are the branch line breaks. The hydraulic LOCA forces that are used in the reactor vessel LOCA analysis are for breaks in the 12" accumulator line (cold leg) and the 14" residual heat removal line (hot leg) for BVPS-1 and for breaks in the 4" line (cold leg) and the 3" line (hot leg) for BVPS-2. Confirm whether the current licensing basis is based on the application of LBB technology. Identify branch line breaks that are used for the RCS LOCA analysis for BVPS-1 and BVPS-2 at the EPU conditions. Confirm whether the pressurizer surge line break, the main steam line break and feedwater line break are considered in the analyses for the EPU conditions. If not, provide technical justification for not including these pipe breaks.

Response:

It is confirmed that the current structural analysis licensing bases for BVPS-1 and BVPS-2 are based on the application of LBB technology. For the current structural analysis licensing basis for BVPS-1, LBB has been applied to eliminate breaks in the main coolant loop and the pressurizer surge line. For the current structural analysis licensing basis for BVPS-2, LBB has been applied to eliminate breaks in the main coolant loop, pressurizer surge line, and branch lines down to and including the 6-inch safety injection lines. For EPU, LBB analyses and evaluations were performed to confirm that the current LBB licensing bases remains applicable to BVPS-1 and BVPS-2 at EPU conditions. The EPU does not include the application of LBB to any lines for which LBB is not currently licensed.

BVPS-1

The current structural analysis licensing basis for BVPS-1 excludes breaks in the main coolant loop piping and the pressurizer surge line piping as permitted under GDC-4 with the appropriate LBB analyses. The justification for use of LBB for the main coolant loop piping is discussed in Section 4.5.2.1 (starting at page 4-57) based on WCAP submittals (Section 4.5.2.4 References 2 through 4) which were reviewed and approved by the NRC (Reference 5). The justification for use of LBB for the pressurizer surge line is discussed in Section 4.5.2.2 (starting at page 4-59) based on a WCAP submittal (Section 4.5.2.4 Reference 10) which was reviewed and approved by the NRC (Reference 11).

As discussed in Section 5.7, new LOCA hydraulic forces for EPU conditions were developed for breaks in the accumulator line on the cold leg and the residual heat removal line on the hot leg. Three sets of LOCA hydraulic forces were developed and used in the structural analyses for the reactor vessel and internals, the main coolant loop, and the replacement steam generators, respectively.

Main steam line breaks and feedwater line breaks are considered in the structural analyses for the main coolant loop and the replacement steam generators. As part of the main coolant loop structural analyses for EPU with replacement steam generators, piping reaction loads (including main steam line and feedwater line break cases) on the NSSS components (i.e. reactor vessel, replacement steam generators, reactor coolant pumps, and loop stop isolation valves) were shown to be acceptable with respect to NSSS component allowable nozzle loads. Since the main steam line and the feedwater line breaks are secondary side breaks and their response on the reactor vessel and internals is very small or almost negligible, they are not considered in the structural analysis performed for the reactor vessel and internals. These secondary line breaks (main steam line and feedwater line) have no significant impact on the reactor vessel and internals.

BVPS-2

The current structural analysis licensing basis for BVPS-2 excludes breaks in the main coolant loop piping, the pressurizer surge line piping, and the branch line piping down to and including the 6-inch safety injection lines as permitted under GDC-4 with the appropriate LBB analyses. The justification for use of LBB for the main coolant loop piping is discussed in Section 4.5.2.1 (starting at page 4-57) based on a WCAP submittal (Section 4.5.2.4 Reference 6) which was reviewed and approved by the NRC (Reference 7). The justification for use of LBB for the pressurizer surge line is discussed in Section 4.5.2.2 (starting at page 4-59) based on WCAP submittals (Section 4.5.2.4 References 12 through 14) which were reviewed and approved by the NRC (Reference 15). The justification for use of LBB on other branch line piping greater than or equal to 6 inches is discussed in Section 4.5.2.3 (starting at page 4-60) based on Section 3 of the WHIPJET Program Final Report (Section 4.5.2.4 Reference 16).

Since all branch lines larger than or equal to a 6-inch diameter were excluded under GDC-4 with the appropriate LBB analyses, LOCA hydraulic forces were developed for breaks in the next most limiting branch lines, which were the 4-inch pressurizer spray line on the cold legs and the 3-inch PORV line on the hot legs. The 3-inch hot leg break was conservatively modeled as a break on the main coolant loop hot leg (in order to bound any smaller hot leg breaks), as the actual PORV line location would have put it into the less limiting pressurizer vapor space instead of sub-cooled liquid.

As discussed in Section 5.7, new LOCA hydraulic forces for EPU conditions were developed for breaks in the 4-inch spray line on the cold legs and the 3-inch PORV line on the hot legs. These new LOCA hydraulic forces were developed and used in the analyses for the reactor vessel and internals. In addition, the main coolant loop has been evaluated with respect to the new LOCA hydraulic forces for EPU conditions. New LOCA hydraulic forces were not developed for the steam generator. Since the structural analysis for the steam generator is based on LOCA hydraulic forces which were originally generated for larger main coolant loop piping breaks (i.e., breaks in the steam generator inlet and outlet nozzles) and subsequently evaluated for large branch line breaks (i.e., breaks in the pressurizer surge line, residual heat removal line and accumulator line) that are bounding for the 4-inch spray line and 3-inch PORV line breaks, an evaluation was performed to confirm that the current steam generator LOCA hydraulic forces remain bounding for 4-inch spray line and 3-inch PORV line breaks at EPU conditions.

The BVPS-2 primary reactor coolant loop piping was not reanalyzed to consider effects from EPU. Existing design basis loadings, including the main steam and feedwater line break loadings, bound loads associated with EPU. Forcing functions for the governing reactor coolant loop branch line breaks were developed for EPU but were bounded by existing design basis loads. Since the main steam line and the feedwater line breaks are secondary side breaks and their response on the reactor pressure vessel is very small or almost negligible, they are not considered in the structural analysis performed for the reactor vessel and internals. These secondary line breaks (main steam line and feedwater line) have no significant impact on the reactor vessel and internals.

N.2 Question: (Applicable to EPU)

In Section 4.2.4, provide a summary evaluation of flow-induced vibration (FIV) including identification of internal components that were reviewed and evaluated for FIV at EPU conditions. Also, provide the predicted maximum response due to FIV for EPU conditions.

Response:

As a part of the Flow Induced Vibration (FIV) assessment to determine the impact of EPU on the BVPS-1 and BVPS-2 reactor vessel internals components, evaluations were performed at the EPU conditions. The reactor internals components that are generally addressed for the FIV consist of the lower internals assembly (core barrel, thermal shield support flexures, thermal shield support bolts and the dowel pins), lower support plate, upper internals guide tubes, and upper support plate. It is shown from the FIV evaluations that at EPU conditions the results are acceptable and that there is no adverse impact on the structural integrity of the BVPS-1 and BVPS-2 reactor internals components.

The calculated stresses and the allowable stresses for FIV are summarized in Table 14.

TABLE 14		
Component	**Calculated Stress (psi)**	**Allowable Stress (psi)**
Core Barrel Beam and Shell Modes	[*]a,c	13,800
Thermal Shield		
• Flexures	[*]a,c	13,800
• Bolts	[*]a,c	16,500
• Dowel Pins	[*]a,c	16,500
Lower Support Plate	[*]a,c	13,800
Upper Support Plate	[*]a,c	13,800
Guide Tubes	[*]a,c	13,800
*Note: a,c Westinghouse Proprietary Information (provided as a separate enclosure)		

N.3 <u>Question</u>: (Applicable to EPU)

On page 4-50, Section 4.4.5, you stated that the BVPS-1 and BVPS-2 Control Rod Drive Mechanisms (CRDMs) and Capped Latch Housings (CLHs) were evaluated for the EPU design parameters and the associated NSSS design transients. In most cases, the existing analyses and evaluations remained applicable and bounding. Where this was not the case, new calculations were performed for the limiting components and the results were evaluated to establish the structural acceptability of the CRDM and CLH pressure boundary components in accordance with the ASME Code. Specify limiting components where the re-analyses were required for operating at the EPU conditions. Also, provide calculated stresses and cumulative usage factors (CUFs) for these limiting components at the EPU conditions.

Response:

The CRDM and CLH limiting components and the calculated stresses and cumulative usage factors (CUFs) for these limiting components at EPU conditions are provided in Section 4.4.5 of WCAP-16307-P, "Beaver Valley Power Station Extended Power Uprate Licensing Report Supplemental Information," September 2004. This supplemental information report was provided as Enclosure 4 to the EPU submittal (L-04-125, October 4, 2004).

In most cases, the existing CRDM and CLH structural analyses and evaluations were shown to be applicable and bounding for EPU conditions. Where this was not the case, new calculations were performed for the limiting components for EPU conditions and the results were used to establish the structural acceptability of the CRDM and CLH pressure boundary components in accordance with the ASME Code. The results of the new calculations for the limiting components for EPU conditions are as follows:

1. CRDMs – Bell Mouthing Analysis for the Upper Joint Threaded Area

   Calculated Stress Intensity = [*] [a,c] psi

   Allowable Stress Intensity = 21,010 psi

2. CRDMs – Fatigue Analysis for the Upper Joint Canopy

   Cumulative Usage Factor (CUF) = [*] [a,c]

   Allowable Cumulative Usage Factor (CUF) < 1.0

3. CLHs – Fatigue Analysis for the CLH Cap

   Cumulative Usage Factor (CUF) = [*] [a,c]

   Allowable Cumulative Usage Factor (CUF) < 1.0

*Note:
[a,c] Proprietary Information provided to NRC previously in WCAP-16307-P.

N.4 Question: (Applicable to EPU)

In Section 4.5, you indicated that the analyses and evaluations for pressurizer surge line stratification and the application of LBB methodology are addressed in this section. The analyses and evaluations for the reactor coolant loop piping and supports are addressed in Section 8.3. However, Section 8.3 does not address how the analysis was performed for the primary reactor cooling loop piping, components and supports and postulated pipe breaks considered for EPU analyses. Provide a summary description of analyses performed for both BVPS-1 and 2, including modeling, assumptions, forcing functions, loads and load combinations used in the analyses for the EPU, especially accounting for the effects of the replacement SGs on the dynamic response to the LOCA and seismic events for BVPS-1. Confirm whether the current EPU evaluations are in accordance with the licensing basis analysis methodology, loads and load combinations, and the Code of record. If not, provide justification for the deviations. Confirm whether the stresses and CUFs provided for BVPS-1 piping, components and supports including the RV and internals at the EPU conditions include the dynamic effect of the replacement SGs. If not, provide technical justification. Also, provide maximum stresses and CUFs at the critical locations for the RV and RCS components (reactor coolant pump, replacement SG/original SG, and pressurizer) supports as a result of the RCS dynamic analyses for the EPU for both BVPS-1 and 2.

Response:

BVPS-1

The BVPS-1 primary reactor coolant loop piping and supports have been evaluated for the Extended Power Uprate (EPU) conditions with consideration of the effects due to the Replacement Steam Generators (RSGs). The evaluations include the EPU system design parameters, transients, and the LOCA dynamic loads. The methods, criteria, load combinations, and requirements used in the existing design basis analyses, and as specified in the BVPS-1 UFSAR Tables 4.1-11 and B.3-5, are applicable for the EPU and RSG evaluations. The analyses were performed in accordance with the code of record for BVPS-1, which is ANSI B31.1 1967, with Addenda through 1971. No new assumptions were made for the EPU and RSG analyses.

The original design basis for BVPS-1 included postulated breaks in the primary reactor coolant loop piping. Through application of LBB technology, which was subsequently allowed by revisions to GDC 4, the need to consider the dynamic effects for the primary reactor coolant loop piping breaks and the pressurizer surge line break was eliminated. Following the application of LBB, the governing pipe breaks in the design basis of the reactor coolant system are the primary branch lines, including the safety injection accumulator and residual heat removal, and the main steam and feedwater piping attached to the steam generators.

The BVPS-1 plant-specific primary reactor coolant loop piping, piping components, replacement steam generators, reactor coolant pumps, and their supports were evaluated for the EPU and RSG conditions using a three-dimensional NUPIPE-SWPC model. The NUPIPE-SWPC computer code was used to perform the thermal, deadload, pressure, seismic and dynamic time history analyses. The dynamic time history analyses were based on the branch line piping breaks and the main steam and feedwater piping breaks.

Changes between the original analyses and the analyses in support of the EPU and the RSGs are:

1) The original primary reactor coolant loop piping system mathematical model was converted from the STARDYNE computer code format to the NUPIPE-SWPC computer code input format,

2) The ASME Code Case N-411 damping values, approved for use at BVPS-1, were used in lieu of 2% damping for the Design Basis Earthquake, and

3) The pipe break loadings were based on EPU conditions with the RSG, instead of pre-uprate conditions with the original steam generators.

The modal superposition method with 1 percent of critical damping applied at each mode was used in the dynamic analyses, which is consistent with the BVPS-1 design basis for the primary reactor coolant loop piping systems. The resultant stresses for the reactor coolant loop piping have been determined, as shown in EPU Licensing Report Table 8.3-1. The calculated stresses are less than the code allowable limits, and are therefore acceptable.

The results from the NUPIPE-SWPC analyses for the primary reactor coolant loop piping includes loads on the major components, nozzles, and supports for the normal operating conditions, upset conditions and the faulted LOCA conditions. These loads were used in the evaluations of the major components, nozzles, and supports (including the replacement steam generators, reactor coolant pumps, and reactor vessel) and have been shown to be acceptable. The component support loads, with consideration for EPU and RSG are less with the application of LBB than those in the original design basis analyses; therefore, the existing analyses stress values are bounding, are within the code allowable limits, and are acceptable. Since the component loadings are less than the existing loads the component supports were not re-analyzed to develop new maximum stress values.

The stresses and CUFs provided for BVPS-1 piping, components and supports, including the RV and internals, at the EPU conditions include the dynamic effect of the replacement SGs.

The component nozzle loads were reconciled with the final loop stress analysis that included the Replacement Steam Generators. The values reported for the nozzle loads in the licensing report are bounding except for the reactor coolant pump nozzle loads reported in Table 4.6.1-2A. The nozzle loads increased slightly as shown below;

	Maximum Upset Stress Intensity (psi)	
RCP Component	**Table 4.6.1-2A (original)**	**Reconciled**
Discharge Nozzle	[*] a,c	[*] a,c
Suction Nozzle	[*] a,c	[*] a,c
Casing	[*] a,c	[*] a,c
*Note: a,c Westinghouse Proprietary Information (provided as a separate enclosure)		

The evaluations used existing design basis information, as stated in the EPU License Report, to assess the impact of EPU conditions, including the fatigue analyses (CUF evaluations). Fatigue analyses were not performed on those piping, components and supports for which the existing design basis did not require a fatigue analysis.

The LOCA hydraulic forces analysis performed for BVPS-1 includes consideration of the replacement SGs, as appropriate. Three sets of LOCA hydraulic forces (i.e., reactor vessel and internals, main coolant loop, and replacement SG) were developed for BVPS-1 at EPU conditions. The LOCA hydraulic forces analysis for the main coolant loop and the replacement SGs were developed using input parameters modeling the replacement SGs since these forces are impacted by the replacement SGs. The structural analyses for the main coolant loop and replacement SGs used these LOCA hydraulic forces and, thus, includes the dynamic effect of the replacement SGs. The LOCA hydraulic forces analysis for the reactor vessel and internals is not impacted by the replacement SGs. This is justified because of the speed at which the LOCA hydraulic forces transient occurs and that the dynamic response of the SG does not affect the peak LOCA hydraulic forces.

BVPS-2

BVPS-2 primary reactor coolant loop piping was not reanalyzed to consider effects from EPU. Existing design basis loadings bound loads associated with EPU. Forcing functions for the governing reactor coolant loop branch line breaks were developed for EPU but were bounded by existing design basis loads. The piping analysis code of record is ASME III 1971, with Addenda through the summer of 1972. Loads and load combinations considered for EPU are consistent with the current licensing basis. Loadings due to temperature, weight, seismic, reactor coolant loop branch breaks, and main steam and feedwater line breaks were included in the current design basis analyses. Maximum piping stresses from the reactor coolant loop piping analyses are shown in EPU Licensing Report Table 8.3-2. Maximum stresses and fatigue usage (CUF) in reactor coolant system component supports are unchanged from the current licensing and design basis.

N.5 Question: (Applicable to RSG & EPU)

The licensee's evaluation provided in Section 4.7.1 for the replacement SGs is rather qualitative. No quantitative results were given for the EPU conditions where the replacement SGs will be implemented. Please provide an evaluation that includes the calculated stresses and CUFs for the critical replacement SG shell, nozzles and internals (baffle, feedwater sparger, steam dryer, flow reflector, tubes) and U-bend tubes. Also provide an evaluation of FIV including fluid-elastic stability and turbulent and vorticity effects on tubes.

Response:

The evaluation provided in Section 4.7.1 of the EPU Licensing Report is qualitative since, as stated in the introduction to this section, the licensing acceptability of replacing the Model 51 original SG components with Model 54F replacement SG components is being evaluated under the provisions of 10 CFR 50.59. The Model 54F replacement SG components are being designed to the EPU conditions (970 MWt/replacement SG). Additional replacement SG design information is provided in WCAP-16415-NP, "Beaver Valley Power Station Unit 1 Replacement Steam Generator Component Report," included as Enclosure 3 to BVPS-1 LAR 320 submitted with FENOC letter L-05-069 dated April 13, 2005. The stress information requested is being generated as part of the design process for the BV-1 replacement steam generators. The information will be included in the Design Stress report. When completed, it will be available on-site for NRC review and inspection.

With respect to flow induced vibration, analyses were performed to evaluate the replacement SG tube bundle and support system (including flow distribution baffle, tube support plates, and anti-vibration bars) for potential vibration and wear. Consideration was given to potential sources of tube excitation including primary fluid flow within the U-tubes, mechanically induced vibration, and secondary fluid flow on the outside of the tubes. The effects of primary fluid flow and mechanically induced vibration are considered negligible during normal operation. The primary source of potential tube degradation due to vibration is due to the hydrodynamic excitation by the secondary fluid on the outside of the tubes. The three potential tube vibration mechanisms due to hydrodynamic excitation by the secondary fluid on the outside of the tubes are vortex shedding, turbulence, and fluidelastic vibration.

The replacement SG analyses showed that calculated fluidelastic stability ratios are within acceptance criteria, displacements and bending stresses from turbulence are small, and calculated wear depths after the 40 calendar year design operating period are within available design margins for local tube wear. The maximum calculated tube wear depth after the 40 calendar year design operating period is within the plugging margin available for steam generator operation. The flow induced vibration and wear analyses therefore demonstrate that the RSG will not experience unacceptable tube degradation due to tube vibration and wear during the 40 calendar year design operating period.

N.6 <u>Question</u>: **(Applicable to EPU)**

CUFs for both BVPS-1 and 2 in the main closure studs based on the design-basis calculation would exceed the Code allowable limit of unity for operation at the EPU conditions. Tables 4.1.1-1A and 4.1.1-1B indicate that the tabulated fatigue usage factors are nearly equal to 1.0. The CUFs for the main closure studs are calculated based on 10,400 and 14,000 cycles for BVPS-1 and BVPS-2, respectively, and pertain to plant loading and unloading, as opposed to 18,300 occurrences in the design-basis calculation. Confirm whether and how you monitor the CUFs in the main closure studs such that the studs will be replaced when the loading/unloading occurrences reach 10,400 and 14,000 cycles for BVPS-1 and BVPS-2, respectively.

Response:

The main closure stud fatigue evaluations originally performed for EPU determined the maximum allowable loading/unloading cycles without exceeding a CUF of unity. Comparison of a conservative estimate of the numbers of cycles already experienced to the number of allowable cycles led to the conclusion that sufficient cycles remained to allow one cycle each day of plant operation for the remainder of the plant life, which is far more than adequate. The evaluation concluded that, "if there is a change in the way the units are operated...closure studs may require additional evaluation for the effects of fatigue usage." A future change to plant operating methods that would cause more that 1 loading and unloading cycle per day is not credible.

The current and projected cycle counts were evaluated for all plant transients with the intent to identify those transients that would approach their design limit and recommend a program for continued cycle counting.

During this evaluation certain design transients were exempted from cycle counting due to the low frequency of current and projected transient occurrence relative to the design frequency. Although the transients are expected to continue to occur in the future, their accumulation rates are so low that they would not reach the design limit. Unit loading and unloading are examples of a transient that does not require further counting.

In order to exempt transients from the cycle counting, both severity and frequency were addressed. The severity of actual unit loading and unloading transients is bounded by design as indicated in EPU Licensing Report Tables 4.1.1-1A and 4.1.1-1B.

A review of transient frequencies indicates that the total number of Unit loading and unloading transients experienced through October 15, 2003 and anticipated are as follows:

	Experienced		Anticipated	
	BVPS-1	BVPS-2	BVPS-1	BVPS-2
Unit loadings:	831	761	1781	2686
Unit unloadings	830	760	1781	2686

Since the actual and anticipated numbers of occurrence are low compared to the allowable design loadings, it was concluded that both the severity and frequency are bounded by design and cycle monitoring is not required.

N.7 Question: **(Applicable to EPU)**

In reference to Section 8.3, discuss the effect of the increased steam flow resulting from EPU that could cause excessive vibration in the main steam and feedwater lines. NB3622.3 requires that piping be designed so that vibration will be minimized. Provide a summary of the evaluation for flow effects on the main steam line vibration, which could be increased for the EPU condition. Confirm whether and how you plan to perform a vibration monitoring program at the startup for the EPU implementation.

Response:

With regard to the effects of the increased steam flow in the secondary system due to the power uprate, main steam and feedwater piping qualification is not specifically performed for effects of vibration due to fluid flow. The original design was based on applicable codes and design standards to minimize vibration and was monitored during start-up to confirm acceptable vibration. The piping is designed to ASME B31.1 (Unit 1) and ASME Section III (Unit 2) for seismic loads, anticipated operating loads and transients loads. The code and standards applied to selecting the pipe supports minimize the potential for vibrations. The original configuration was monitored for the original plant start-up for vibration. The piping was re-analyzed for the EPU conditions and the existing pipe support system was found to be adequate without modifications. As was done for the original power ascension, the piping will be monitored during power ascension to the EPU power level for vibration.

To ensure that changes resulting from the EPU do not cause excessive vibration that could be detrimental to system performance, vibration monitoring will be performed during implementation of EPU to identify sources of vibrations and appropriate corrective actions to be taken to eliminate or minimize these vibrations. The EPU represents an incremental change in flow in the main steam piping and feedwater piping, which could potentially increase the vibration level of the piping system. Piping within these two systems is to be monitored to obtain baseline data for determining future changes in vibration characteristics. During power ascension of the EPU, these piping systems will continue to be monitored to identify areas with potentially significant changes in vibratory behavior. For additional details on vibration monitoring during power ascension, refer to response to question N.13.

Special emphasis will be placed on monitoring for vibration of branch connections off the main steam piping and feedwater piping. Vibration monitoring and evaluation of the measured data will be in accordance with ASME OM-S/G-2003, Part 3, "Standards and Guides for Operations and Maintenance of Nuclear Power Plants," and the acceptance criteria provided in ASME OM-S/G-2003, Part 3, will be utilized. Compensatory and corrective actions will be taken, where required, to comply with the specified limits.

N.8 <u>Question</u>: (Applicable to EPU)

In reference to Section 8.3.3, provide the technical basis for not evaluating the piping and support systems where the increase in temperature, pressure and flow rate are less than 5% of the current rated design-basis condition. Your justification provided on page 8-94 is qualitative and nonspecific. For instance, you stated that conservatism <u>may</u> include the enveloping of multiple thermal operating conditions as well as not considering pipe support gaps in a thermal analysis. We can not draw a conclusion from these undefined qualitative statements. The technical justifications should be based on specific quantitative assessment or intuitively conservative deduction in order for the NRC staff to accept your conclusions.

Response:

Additional evaluations were performed for EPU for BVPS1 and BVPS-2 beyond those qualitative assessments described in Section 8.3. For all piping and support systems where there was an increase in temperature, pressure and/or flow due to EPU conditions, that is, a change factor was determined to be greater than 1.0, a detailed assessment was performed. The critical pipe stress levels of all affected piping systems are presented in the tables in Section 8.3. The tables identify the maximum stress value for each system and show the resulting change in pipe stress levels of the piping and support system due to EPU as compared to the existing design basis stress levels. The tables also show the resulting design margin following EPU where design margin is defined as calculated stress divided by allowable stress. As shown on the tables in Section 8.3, all the resultant pipe stresses for EPU are less than the allowable limit.

N.9. <u>Question</u>: (Applicable to EPU)

Section 10.1, Motor Operated Valves (MOVs), in the EPU Licensing Report for BVPS-1 and 2 states that the proposed 8% EPU will not change any program controls or existing licensing commitments for MOVs at BVPS-1 and 2. Section 10.1 states that the differential pressure applied in the MOV calculations is conservative, but, that plant modifications might affect some individual valve differential pressures. Section 10.1 also states that any required revised MOV settings and testing will be performed in accordance with the established MOV Program at BVPS-1 and 2. The licensee is requested to discuss with examples its evaluation of the impact of the EPU conditions on safety-related MOVs, including any changes in individual valve differential pressures. The discussion should address any changes in ambient temperature or operating voltage that might impact motor output of MOVs addressed in response to GL 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," and GL 96-05, "Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves."

Response:

Motor operated valve (MOV) calculations for valves in the GL 89-10 program were reviewed for potential impact due to EPU. It was determined that maximum differential pressure across each valve is calculated conservatively based on worst case scenarios and that these scenarios are unaffected by EPU. Based on this determination, EPU does not impact any previous differential pressure (DP) responses or conclusions relative to the GL 89-10 program, as discussed below.

The EPU requires a change to the HHSI pump to increase the pump curve. This change potentially increases the DP for various valves. The opening stroke DP for the SI-867A, B, C, D valves (the BIT inlet and Outlet Valves) for BVPS-1 and 2SIS*867A, B, C, D for BVPS-2 were evaluated for the higher head pump curves and determined to be acceptable.

The acceptability of the system MOVs to close with the higher system pump discharge pressure was determined in accordance with Westinghouse Owners Group WCAP 13097, System Operating Basis for Motor Operated Valves, Rev. 0. As a result, there is no change for the closing stroke for valves affected by the higher operating pressure of the HHSI pump and they are acceptable for the EPU conditions.

As noted in Section 9.19 of the EPU Licensing Report, the 480 V System was reviewed and found adequate to support EPU. Voltage available at the 480 V loads after accounting for the load changes due to EPU are higher than assumed in MOV torque calculations under all evaluated conditions. The EPU voltage profiles, therefore, support the current MOV calculations.

The effects of temperature changes due to power uprate on MOV operation, specifically electric motor starting torque loss at increased elevated temperatures are addressed below.

BVPS-1

The only MOVs experiencing an increased environmental temperature as a result of power uprate are those located in the Main Steam Valve House. Specific valves are MOV-MS-101A/B/C and MOV-MS-105.

Table 15

Valve No MOV-	Description	Equipment Function	Analysis
1MS-101A 1MS-101B 1MS-101C	Motor for Limitorque Operator	Motor actuator for MS trip bypass valves. These valves allow pressure equalization across the trip valve disc and the warming of MS lines when trip valve is closed.	These valves perform their function under no load and low power conditions and are closed under full load conditions. No load and low power conditions do not change with power uprate. Therefore, power uprate has no significant impact on MS trip bypass valves.
1MS-105	Motor for Limitorque Operator	Motor actuator for valve that feeds main steam to TD AFW pump. Required to be opened for MSLB.	This motor operator fails in the position it is in. Since the normal system alignment for this valve is open, failure of the motor will leave the valve in the safe position (i.e., the open position).

Motor operated valves MOV-1MS-101A/B/C are not impacted by temperature increases in conjunction with power uprate because they perform their functions at no load and low power levels. As a result their safety function will be maintained.

Motor operated valve MOV-1MS-105 is not impacted by temperature increases in conjunction with power uprate because the motor operator fails such that the valve will be left in the safe (i.e., open) position. As a result the safety function will be maintained.

BVPS-2

The only MOVs potentially experiencing an increased environmental temperature are those located within the Main Steam Valve House. Specific valves are 2CCP-MOV118, 2CCP-MOV119 and 2CCP-MOV120.

Table 16			
Valve No 2CCP-	**Description**	**Equipment Function**	**Analysis**
MOV118 MOV119 MOV120	Limitorque / Reliance operated valve	Motor provides positive closure to isolate non-safety component cooling portion from safety component cooling portion of the CCP system. The valves close on either a CIA signal or on low level in the surge tank.	The valves are located outside containment in the Instrument Air Compressor room in the Main Steam Valve House. A CIA signal is due to a LOCA or MSLB in containment. Therefore, there is no increase in the room temperature for these events. The valves are not expected to function for the postulated MSLB outside containment.

Motor operated valves 2CCP-MOV118, 119 and 120 are not impacted by temperature increases in conjunction with power uprate because they do not have to function for the MSLB outside of containment.

GL 96-05 concerns the Periodic Verification program required for MOVs. When the HHSI pumps were replaced, impact considerations of the higher head requirements were assessed for the MOVs and their baseline information within the Periodic Verification program. Revised MOV settings were made as required.

N.10 *Question:* **(Applicable to EPU)**

Section 10.1 of the EPU Licensing Report states that evaluations to address GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves," have been reviewed to determine if there would be any adverse effects due to EPU operation at BVPS-1 and 2. The licensee is requested to discuss with examples its evaluation of safety-related power-operated gate valves in response to GL 95-07, including consideration of any changes in ambient temperature on the potential for pressure locking or thermal binding.

Response:

The GL 95-07 documentation was reviewed and evaluations were performed to determine if operation at EPU conditions would adversely affect any conclusions or qualifications previously approved by the NRC. Of particular interest were the following:

1. BVPS' 2/13/96 response to GL 95-07, including an attached Pressure Locking Thermal Binding (PLTB) Evaluation Matrix.
2. BVPS' 7/24/96 response to the NRC's 6/24/96 RAI.
3. BVPS' 7/8/99 response to the NRC's 4/20/99 RAI.
4. The NCR's Safety Evaluation (TAC Nos. M93429 and M93430) and comments and conclusions therein.

The conditions detailed in the original evaluation remain applicable for the EPU. The subject valves are summarized in Table 17. The bases for concluding that all valves remain acceptable at uprate conditions are as follows:

A) Various valves were modified to eliminate the potential for PLTB. This conclusion is unaffected by the EPU (Table 17, Group A).

B) Various valves are not susceptible to pressure locking because either (1) the valves are shut during certain accident scenarios, (2) the valves are not exposed to thermal-induced pressure locking conditions, or (3) the valves are not opened until several hours into the event (Table 17, Group B). The time at which the MOVs-1SI-869A/B are used for aligning recirculation to the hot legs has been reduced from the original time of 14.5 hours to 6.5 hours. The MOVs are not exposed to thermal-induced pressure locking and the impact of EPU does not introduce conditions that expose the MOVs to thermal-induced pressure locking. In addition, the process conditions (normal or accident) for which these valves are susceptible to pressure locking is not impacted by EPU. However the original basis for concluding that these MOVs are not susceptible to pressure locking is that seat or packing leakage during the 14.5 hours would prevent the valves from pressure locking. With the reduced time of 6.5 hours the MOVs could be susceptible to pressure locking if the pressure decay (leakage) is not sufficient. These MOVs would be expected to exhibit leakage and pressure decay, minimizing the potential for pressure locking. However, a conservative assessment was performed based upon the pressure locking thrust prediction methodology developed by Commonwealth Edison. This evaluation shows that these valves have sufficient actuator and valve margin to open under bonnet pressure locking conditions. The original justification for 2RHS*MOV720A/B is unchanged by EPU.

C) Various valves were listed in the original BVPS GL 95-07 response as being able to open under pressure locking conditions based on use of a pressure-locking thrust prediction methodology developed by Commonwealth Edison (Table 17, Group C). These valves are acceptable under EPU conditions based on the following:

- The valves in the SI system (2SIS-MOV863A/B, 2SIS-MOV8811A/B, and 2SISMOV-8890A/B) were subsequently modified to eliminate the potential for PLTB. One disc of each valve was drilled to eliminate the possibility of PLTB. Due to these modifications, the valves are now grouped under "A" in the Table 17.
- As noted in reference 3 above, analyses have shown that the valves have sufficient margin to operate under the required conditions. EPU has not changed these conditions. Also as noted in the reference 3 response, Operating Procedures have been changed for the PORV Block Valves for thermal binding considerations, and EPU has not required any additional changes for these valves. Ambient Temperatures remain essentially the same for the Auxiliary and Containment Buildings. Therefore there are no changes in regard to PLTB considerations. Containment accident conditions remain within the original design values.

Table 17
GL 95-07 Valve List

A. Valves Modified to Eliminate PLTB:	
MOV-1SI-860A/B	Low Head Safety Injection Pump Suction
MOV-1SI-867A/B/C/D	Boron Injection Tank Isolation
MOV-1RC-535	Pressurizer Power Operated Relief Valve (PORV) Block
2RHS*MOV701A/B	RHR Pump Isolation
2RHS*MOV702A/B	RHR Pump Isolation
2SIS*MOV836	High Head Cold Leg Injection
2SIS*MOV867A/B/C/D	Boron Injection Tank Isolation
2SIS*MOV869A/B	Safety Injection (SI) Pump Hot Leg Isolation
2SIS*MOV8889	SI Pump Discharge Isolation
2SIS*MOV863A/B	SI to Charging System
2SIS*MOV8811A/B	Recirculation Spray to SI
2SIS*MOV8890A/B	SI Pump Recirculation
B. Valves not Susceptible to Pressure Locking:	
2RHS*MOV720A/B	RHR System Return Line to SI
C. Valves Capable of Opening under Pressure Locking Conditions	
MOV-1RC-536/537	Pressurizer Power Operated Relief Valve (PORV) Block
2RCS*MOV535/536/537	Pressurizer PORV Block
MOV-1SI-869A/B	Charging to Reactor Coolant System Hot Leg Injection

N.11 Question: (Applicable to EPU)

Section 10.2, the Air Operated Valve (AOV) Program of the EPU Licensing Report states that the program at BVPS-1 and 2 for testing, inspection, and maintenance of AOVs was reviewed for impact from EPU operation, and that these reviews did not identify any safety-related AOVs that would be adversely affected by EPU operation (other than the feedwater control valves that will be modified to increase flow capacity). The licensee is requested to discuss with examples its evaluation of safety-related AOVs for potential impact from EPU operation.

Response:

BVPS has in place an AOV Program for testing, inspection and maintenance of valve air operators. This AOV program used is consistent with the "Joint Owners Group Air Operated Valve Program".

Per the AOV Program, valves are categorized 1 – 4. Category 1 valves have an active safety function and have high safety significance. Category 2 valves have an active safety function and do not have high safety significance. Category 3 valves may affect plant availability, capacity factor, heat rate, or have high maintenance costs. Category 4 valves are in the Maintenance Rule but do not fall in Categories 1, 2, or 3.

The following AOV Program valves are examples of safety-related AOVs that were evaluated for potential impact from EPU operations:

1. The high head safety injection (HHSI) pump impellers are being replaced for the EPU. This will affect several AOVs, which are listed in Table 18 with their categorization. The Unit 1 HHSI pump rotating assemblies have already been replaced. One of the Unit 2 HHSI pump rotating assemblies has already been replaced.

Table 18

Valve Number	Category
FCV-1CH-122 Charging Flow To Regenerative Heat Exchanger Inlet Control	1
FCV-1CH-160 Fill Header Flow Control	2
2CHS-FCV122 Charging Pumps Discharge Flow Control Valve	1
TV-1SI-884A BIT Recirculation To Boron Injection Surge Tank Isolation	2
TV-1SI-884B BIT Recirculation To Boron Injection Surge Tank Isolation	2
TV-1SI-884C BIT Recirculation To Boron Injection Surge Tank Isolation	2

The evaluations were done using the replacement HHSI pump shut off heads, and it was concluded that the valves are acceptable for EPU operation

2. The Feedwater Regulating Valves (FWRV) and the Main Steam Isolation Valves (MSIV) have increased flow requirements for the EPU. The Unit 1 FWRV trims are being modified to increase the valve Cv. A modified cage will be installed which will have a slightly larger seat diameter. This will slightly increase the seating load requirements. Sufficient operator margin remains to provide the required loads for the new cage trim. The Unit 2 FWRVs are being replaced due to maintenance considerations and the new valves will have an increased Cv for EPU conditions. The 2FWS-FCV-488 valve has already been replaced. The Differential Pressure and Thrust Determination calculations for the replacement valve has been completed. These are categorized as in Table 19.

Table 19	
Valve Number	**Category**
FCV-1FW-478 (FWRV)	2
FCV-1FW-488 (FWRV)	2
FCV-1FW-498 (FWRV)	2
2FWS-FCV-478 (FWRV)	2
2FWS-FCV-488 (FWRV)	2
2FWS-FCV-498 (FWRV)	2
TV-1MS-101A (MSIV)	2
TV-1MS-101B (MSIV)	2
TV-1MS-101C (MSIV)	2
2MSS-AOV-101A (MSIV)	2
2MSS-AOV-101B (MSIV)	2
2MSS-AOV-101C (MSIV)	2

The FWRVs will operate at lower normal operating pressures since at EPU flowrates the pumps will operate further out on their curves. There are no changes being made to the Condensate or Main Feedwater pumps due to uprate. The increased friction losses at the higher flows will further act to reduce normal operating pressures. The FWRVs are balanced cage guided port throttling control valves.

The Unit 1 Main Steam Isolation Valves (TV-1MS-101A, B, C) are exempted from the AOV Program Procedural requirement to have a Design Basis Review calculation performed documenting the capability of the actuator to position the valve under Maximum Expected Differential Pressure (MEDP). This exemption is based on the applicable design requirements for the subject valves which indicate that the actuator need only to be able to open the valve with 4 psi differential pressure across the valve and an applied actuator air pressure of 70 psi. At issue is the fact that the valve is not required to open under operating, abnormal or accident conditions. The function of the actuator is to open the valve with little or no differential pressure, and to maintain the valve open during operation. The safety function of the valve is to close rapidly on a Main Steam Isolation signal. Closure is accomplished by exhausting air from the actuator, which will cause the valve disc to drop into the steam flow path, which will rapidly close the valve. The actuator's ability to maintain the valve in the open position during plant operation is adequately demonstrated during power operations. The reliability of the valve to maintain the open position is assured through appropriate design requirements, preventative and corrective maintenance and testing.

N.12 <u>Question:</u> (Applicable to EPU)

Section 10.5, the Inservice Testing (IST) Program of the EPU Licensing Report states that EPU analyses and plant modifications might change specific acceptance criteria for the IST Program at BVPS-1 and 2. The licensee is requested to discuss with examples its 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 Program resulting from that evaluation.

Response:

As a result of the BVPS-1/BVPS-2 EPU evaluations, various mechanical system components which provide active safety-related functions, will require installation or modification. These include for BVPS-1, installation of fast closing Feedwater isolation valves, and for BVPS-1/BVPS-2, installation of Charging Pump rotating assemblies to extend the pump runout limits. There are no new safety-related functions required of existing equipment.

Specific IST program changes for EPU are:

- New fast-acting Feedwater Isolation Valves (HYV-1FW-100 A, B, and C) were installed during refueling outage 1R16 and have been added to the BVPS-1 IST Program (Rev. 15, 11/18/04) for testing during cold shutdowns. As a result, the Feedwater System Isolation Check Valves (1FW-156A, B and C) were changed from motor operated check valves to simple check valves during refueling outage 1R16. The stroke time test for the valves was deleted from the BVPS-1 IST Program (Rev.16, 12/7/04), and the check valves continue to be tested in the closed direction via a leak test at each refueling outage.
- The High Head Safety Injection Pumps at BVPS-1 have already been modified with higher head rotating assemblies. This will also be completed for BVPS-2 prior to EPU operation. Because of this, the EPU analysis for SBLOCA requires the HHSI system to be re-balanced and the Minimum Operating Point (MOP) curves to be revised. As a result, the new MOP curves will be incorporated into the BVPS-1 and BVPS-2 IST Programs, and ECPs (Engineering Change Packages) will implement the required IST implementing procedure changes for new ASME XI delta-p limits prior to EPU operation.
- Auxiliary feedwater flow requirements were revised in the safety analyses performed to support EPU. The specific events which credit AFW flow are the Loss of Normal Feedwater, Feedline Break, and the Small Break LOCA. Changes were made in the number of pumps assumed to operate for each event and these are discussed in the revised Technical Specification bases. As a result of these changes, the minimum pump performance (MOP) curves and check valve flow criteria will need to be updated in the IST program.
- As part of the LAR 302/173, items 13 and 20 in the request regarding tolerance setting changes for the Main Steam Safety Valves (SV-1MS-101A, B, C, 102 A, B, C, 103 A, B, C, 104 A, B, C, and 105 A, B, C) and (2MSS-SV-101 A, B, C, 102 A, B, C, 103 A, B, C, 104 A, B, C, and 105 A B, C) and the Reactor Coolant Pressurizer Safety Valves (RV-1RC-551 A, B, and C) and (2RCS-RV-551 A, B, and C). Specifically, the tolerance settings for the Main Steam Safety Valves (MSSVs) and the Pressurizer Safety Valves is increased.

- In Technical Specification Table 3.7-2, the MSSVs with the lowest setting pressure will be limited to a lift setting tolerance of +1/-3%. The lift setting tolerance for the remaining MSSVs will be limited to a lift setting tolerance of ± 3 percent, which is a change from the current lift setting tolerance of +1/-3%.
- Technical Specification 3.4.3 will be modified to change the upper tolerance for the Pressurizer Code Safety Valves from +1% to +3% for BVPS 1, and from +1% to +1.6% for BVPS 2. The current lift setting tolerance at both units is +1/-3%. The lower tolerance for both units is unchanged at –3%.

Both of these changes will be incorporated into the BVPS-1 and BVPS-2 IST Program implementing procedures prior to EPU operation.

Ambient conditions have no impact on IST Program components. Equipment inside containment has been evaluated for increased post-accident temperatures and documented in Section 10.10 of the EPU licensing Report.

There are no changes to the degraded voltage levels as a result of EPU, and therefore, there are no power supply effects on the MOVs or pumps.

N.13 Question: (Applicable to EPU)

Section 13, Testing of the EPU Licensing Report states that steady state data will be taken at 95% and 100% of the current RTP level at BVPS-1 and 2 in order to project operating performance parameters for the EPU power level before the current RTP level is exceeded. Section 13 also states that additional steady state operating data will be obtained and evaluated at approximately 2.5% increments between the current licensed RTP and the EPU power level with any data discrepancies resolved prior to proceeding with power ascension. Table 13-10 of the EPU Licensing Report provides a brief abstract of system vibration testing for EPU conditions at BVPS-1 and 2, but does not specify hold points during power ascension, systems to be monitored, data to be collected, or methods of data collection. The licensee is requested to discuss in more detail its 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, and planned data evaluation.

Response:

The EPU LAR Supplemental information provided in FENOC Letter L-05-026, Attachment D identifies the system and parameters to be included in the Power Ascension testing.

During power ascension, adverse flow effects could potentially occur due to:

a. Oscillating flow control valves
b. Fast closure and/ or opening of automatic air or motor operated valves
c. Tripping of pumps
d. Inadvertent operator action
e. Check valve slam

The power ascension will be controlled using approved procedures to avoid the above conditions.

There are two separate procedures associated with question N.13. One procedure is the Sequence Procedure and the second is the System Vibration Test for EPU. Overlap exists between these procedures.

Sequence Procedure:

The Sequence Procedure collects steady state data at the current power level. Collected data is evaluated for two main purposes: (1) to establish valid baseline data, and (2) to quantify process changes for a percent change in power. Data is then extrapolated to make projection in process parameters for the subsequent approximately 2.5% increase in power.

After approximately 2.5% power increase and when the plant is stable, plant data is again obtained. Collected data is compared to projected values, design limits, and licensing limits. Most data will have evaluation criteria, but data is collected for trending. Evaluation criteria are classified as either Level 1 or Level 2.

Level 1 criteria pertain to Technical Specifications, Design Limits, Core Limits, and stable operation of NSSS controls. If a Level 1 acceptance limit is not satisfied, then power ascension is suspended and the plant is placed in a status judged satisfactory by the Shift Manager, using guidance of the plant procedures and Technical Specifications. Resolution of the problem must be immediately pursued by equipment adjustments or through the engineering evaluation process (Corrective Action Program) as appropriate. Following resolution, the applicable portion of the Sequence Procedure is repeated to verify that the Level 1 acceptance limit is satisfied. A description of the problem will be included in the Test Report.

Examples of Level 1 Acceptance Limits that could potentially be affected are as follows:

- Inability to maintain Main Condenser Pressure adequately below the plant trip set point.
- Inability of NSSS Control Systems to maintain Steam Generator Level without continued operator action.
- Reactor core parameters and indications exceeding any limitations stated in the Core Operating Limits Report (COLR).
- Inability of the Chemical and Volume Control System to maintain RCS volume and a steady RCS boron concentration.

Level 2 criteria pertain to expectation of system performance whose characteristics can be improved by equipment adjustments. If a Level 2 acceptance limit is not satisfied, then power ascension may proceed after an investigation by testing, engineering, and/ or operations personnel.

If a Level 2 acceptance limit is not satisfied after a reasonable effort, the Testing Lead may choose to proceed with power ascension. The Testing Lead will document the results, and indicate who was contacted for resolution and indicate if a Condition Report is required. A description of the problem will be included in the Test Report.

Examples of Level 2 Acceptance Limits that could potentially be affected are as follows:

- Decrease in Main Feedwater, Condensate, or Heater Drain Pump suction pressure below projected value
- A fully open (>85%) Feedwater Heater Level Control Valve
- High Main Turbine vibration
- Pressurizer Backup Heater operation is required to maintain Reactor Coolant System pressure while at steady state power
- Increase in pipe or component vibration over baseline vibration (visual observation)
- Increase in control valve oscillation over baseline oscillation (visual observation)
- Feedwater Control Valve open greater than 80%

The collected data is used to make projection for the next power increase. After data has been evaluated and all deficiencies resolved, power is again increased. The above process is repeated until the plant is at the EPU power level.

Data is collected from the permanent plant instruments and augmented by test equipment. Also included are system walkdowns. Experienced personnel (plant engineers, operators, structural engineers, etc.) perform the walkdowns. Vibration testing (or further examination) would only be performed as a result of specific equipment being flagged from the walkdowns.

The Sequence procedure calls out for the performance of the System Vibration Test for EPU at both the current power level and the EPU power level.

System Vibration Test:

At approximately the current power level (90 to 93% of EPU), the initial performance of the System Vibration Test for EPU is performed. System walkdowns are performed and measurements are obtained (if required) to establish baseline conditions at the current licensed power level.

During power ascension, flow induced vibrations are detected by visual observation. Any measurements are first obtained with a simple ruler. If simple mechanical measurements do not provide adequate data to evaluate the noted vibration, then additional instrumentation will be employed to obtain necessary data.

At the EPU power level, the System Vibration Test for EPU is again performed. System walkdowns are performed and measurements are obtained (if required) to verify that vibrations are within acceptable limits. Noted deficiencies will be evaluated for impact and corrected to allow safe operation at the EPU power. If any vibration measurements or observation are determined to be a safety concern, then power would be reduced until vibration levels are within acceptable limits. Escalation would not continue until the vibration issue is resolved.

N.14 Question: **(Applicable to EPU)**

The licensee is requested to discuss its evaluation of potential FIV effects due to the increase in steam flow resulting from EPU conditions at BVPS-1 and 2. The evaluation should include the RV internals, and steam and feedwater systems and their associated components, including impact on structural capability and performance during normal operations, anticipated transients (initiation and response), and design-basis conditions; and preparation for responding to the potential occurrence of loose parts as a result of the EPU. The evaluation should also include calculations, when applicable, of the fluid-elastic stability ratio, and stresses due to turbulent and vortex shedding.

Response:

The portion of this question pertaining to potential FIV effects due to the increase in steam flow on the RV internals will be addressed relative to the steam generators (SGs) since the BVPS units are pressurized water reactor plants.

For BVPS-1, the Model 54F replacement SG components are being designed for the EPU conditions (970 MWt/replacement SG), including the associated steam flows. Consequently, with respect to the BVPS-1 replacement SG components, there is no increase in steam flow due to the EPU. Additional information regarding the FIV analysis performed for the replacement SGs is provided in the response to question N.5.

For BVPS-2, the Model 51M steam generators will experience an increase in steam flow due to the EPU. To address the increase in steam flow and potential FIV effects, a Generic Letter 88-02 tube vibration induced fatigue analysis was performed for EPU conditions to address those tubes subject to high cycle fatigue. This analysis is reported in Section 4.7.2.3 of the EPU Licensing Report. The tubes identified in this analysis as being susceptible to high cycle fatigue envelop all of the other tubes for stability ratio concerns. Therefore, the tubes not identified for remediation have stability ratios less than 1.0 and are acceptable.

For FIV effects on the BVPS-2 steam generator tubing as a result of turbulence and vortex shedding, bending stresses with the tubes are typically two orders of magnitude less than the endurance limit of the material, and turbulent displacement of the tubes is on the order of several mils, much less than ½ the tube separation. Therefore, since the base stresses and displacements are not significant, even a large percentage increase resulting from EPU will not lead to any fatigue or tube contact concerns. For the calculated maximum uprate factor of 43% (ratio of density and velocity before and after EPU), tube turbulence displacement and stress increases will not be significant and will not lead to unacceptable stress or displacements in the steam generator tubes. Therefore, the EPU will not impact the qualification of the BVPS-2 steam generator tubing for FIV effects.

The BVPS-1 and BVPS-2 SGs employ a secondary moisture separator (i.e., steam dryer) design that consists of a multi vane assembly. In this assembly, the steam/water mixture must pass through a torturous path that results in water droplets becoming entrained in the nooks/crannies built into the vane assembly. These water droplets contact the vane and are then pulled down by gravity to a drain. This design works effectively due to the reduced velocity of the steam as it enters the gaps between the individual vanes that make up the dryer. This effectiveness is due in large part to the large surface area associated with the secondary separator. A conservatively high inlet moisture content (25%) to the dryer is assumed for additional assurance that performance objectives are met. Due to the design of the secondary separator, FIV has never been a concern because:

1. Low fluid velocities associated with the dryer due to large surface areas, and
2. High stiffness of the assembly due to the torturous path associated with each vane (high stiffness results in higher natural frequencies which result in a reduced potential for FIV).

The low velocity and low density of the steam entering the secondary separators result in low dynamic pressures and low FIV loading of the secondary separators. Physical inspections performed for steam generator secondary moisture separators on operating plants have not found indications of high flow and/or FIV of the separators.

Several Westinghouse designed 3-loop plants (e.g., Virgil C. Summer Nuclear Station and Shearon Harris Nuclear Power Plant) have Westinghouse designed steam generators with secondary separators (single tier design) similar in design to BVPS-1 and have been operating for a number of years at approximately 970 MWt/SG without encountering FIV of the separators. The Joseph M. Farley Nuclear Plant Units 1 and 2 have been operating for a number of years with Westinghouse Model 54F replacement SGs, similar in design to the BVPS-1 Model 54F replacement SGs, but at the lower power level of 923.22 MWt/replacement SG. Since Farley is operating at a lower power level than BVPS-1, the BVPS-1 separator package was modified (i.e., larger inlet) so that the flow velocity would be similar, ~3.5ft/sec. Summer and Harris have slightly different center-to-center spacing but the effective flow velocity is still approximately 3.5 ft/sec. The Summer, Harris and Farley operating experience provide assurance that BVPS-1 can operate without FIV damage at EPU conditions.

The North Anna Power Station Units 1 and 2 (Westinghouse designed 3-loop plants) have Westinghouse designed steam generators with secondary separators (two tier design) similar in design to BVPS-2 and have been operating for a number of years at approximately 970 MWt/SG without encountering FIV of the separators. The North Anna operating experience provides assurance that BVPS-2 can operate without FIV damage at EPU conditions.

In the Westinghouse SG design, the secondary separator is suspended below a cylinder attached to the shell. This provides flexibility independent of the shell thermal and pressure expansions. Operating experience with no known defects provides confidence that the BVPS secondary separators will function as designed similar to the other plants.

As described in the response to question B.3, the change in secondary side flow rates is judged negligible with regard to loose part impact on SG tube integrity. The recent cases of loose part wear at BVPS-2 have established actual depths bounded by 40% through wall, with most cases involving a precursor signal at the previous inspection(s). As the recently observed wear rates remain acceptable with regard to impact to SG tube leakage integrity, the minimal depth and length of these indications suggests large margins against the performance criteria. Additionally, FENOC performs FOSAR (Foreign Object Search and Retrieval) at each BVPS-1 and BVPS-2 outage.

With regard to the effects of the increased flow in the secondary systems due to the EPU, the FIV responses are provided in the responses to questions N.7 and N.13.

The main steam and feedwater systems, including their associated components, have been evaluated for impact on structural capability considering parameter changes due to EPU conditions for BVPS-1 and BVPS-2. The evaluations for BVPS-1 include the impact on structural capability due to the RSGs. The main steam and feedwater systems, and their components, have been evaluated for normal operating conditions, and the anticipated fluid transient conditions. The structural capability is confirmed by evaluation of the stresses in comparison to the design basis allowable stress. Pipe supports, such as: snubbers, hangers, struts, guides, and anchors, equipment nozzles, valves, and penetrations were evaluated by reviewing the piping interface loads due to the increases in pressure, temperature, and flow for the affected piping systems. As a result of the evaluations, there were no required modifications to the piping systems or the pipe supports due to the EPU for BVPS-1 and BVPS-2, or RSG for BVPS-1.

L-05-078 Enclosure 2

Proprietary and nonproprietary responses to RAI questions N.2 and N.4

Responses to NRC Request for Additional Information on N.2, "BVPS Reactor Vessel Internals Calculated Stress Values for Flow Induced Vibration" and N.4, "BVPS Reactor Coolant Pump Component Maximum Upset Stress Intensities"

BVPS EPU Submittal

May 26, 2005

Westinghouse Electric Company LLC
P.O. Box 355
Pittsburgh, PA 15230-0355

N.2 Question:

In Section 4.2.4, provide a summary evaluation of flow-induced vibration (FIV) including identification of internal components that were reviewed and evaluated for FIV at EPU conditions. Also, provide the predicted maximum response due to FIV for EPU conditions.

Response:

As a part of the Flow Induced Vibration (FIV) assessment to determine the impact of EPU on the BVPS-1 and BVPS-2 reactor vessel internals components, evaluations were performed at the EPU conditions. The reactor internals components that are generally addressed for the FIV consist of the lower internals assembly (core barrel, thermal shield support flexures, thermal shield support bolts and the dowel pins), lower support plate, upper internals guide tubes, and upper support plate. It is shown from the FIV evaluations that at EPU conditions the results are acceptable and that there is no adverse impact on the structural integrity of the BVPS-1 and BVPS-2 reactor internals components.

The calculated stresses and the allowable stresses for FIV are summarized in Table 14.

Table 14

Component	Calculated Stress (psi)	Allowable Stress (psi)
Core Barrel Beam and Shell Modes	[ ]^{a,c}	13,800
Thermal Shield		
• Flexures	[ ]^{a,c}	13,800
• Bolts	[ ]^{a,c}	16,500
• Dowel Pins	[ ]^{a,c}	16,500
Lower Support Plate	[ ]^{a,c}	13,800
Upper Support Plate	[ ]^{a,c}	13,800
Guide Tubes	[ ]^{a,c}	13,800

*Note:
^{a,c} Westinghouse Proprietary Information (provided as a separate enclosure)

N.4 Question:

In Section 4.5, you indicated that the analyses and evaluations for pressurizer surge line stratification and the application of LBB methodology are addressed in this section. The analyses and evaluations for the reactor coolant loop piping and supports are addressed in Section 8.3. However, Section 8.3 does not address how the analysis was performed for the primary reactor cooling loop piping, components and supports and postulated pipe breaks considered for EPU analyses. Provide a summary description of analyses performed for both BVPS-1 and 2, including modeling, assumptions, forcing functions, loads and load combinations used in the analyses for the EPU, especially accounting for the effects of the replacement SGs on the dynamic response to the LOCA and seismic events for BVPS-1. Confirm whether the current EPU evaluations are in accordance with the licensing basis analysis methodology, loads and load combinations, and the Code of record. If not, provide justification for the deviations. Confirm whether the stresses and CUFs provided for BVPS-1 piping, components and supports including the RV and internals at the EPU conditions include the dynamic effect of the replacement SGs. If not, provide technical justification. Also, provide maximum stresses and CUFs at the critical locations for the RV and RCS components (reactor coolant pump, replacement SG/original SG, and pressurizer) supports as a result of the RCS dynamic analyses for the EPU for both BVPS-1 and 2.

Response:

BVPS-1

The BVPS-1 primary reactor coolant loop piping and supports have been evaluated for the Extended Power Uprate (EPU) conditions with consideration of the effects due to the Replacement Steam Generators (RSGs). The evaluations include the EPU system design parameters, transients, and the LOCA dynamic loads. The methods, criteria, load combinations, and requirements used in the existing design basis analyses, and as specified in the BVPS-1 UFSAR Tables 4.1-11 and B.3-5, are applicable for the EPU and RSG evaluations. The analyses were performed in accordance with the code of record for BVPS-1, which is ANSI B31.1 1967, with Addenda through 1971. No new assumptions were made for the EPU and RSG analyses.

The original design basis for BVPS-1 included postulated breaks in the primary reactor coolant loop piping. Through application of LBB technology, which was subsequently allowed by revisions to GDC 4, the need to consider the dynamic effects for the primary reactor coolant loop piping breaks and the pressurizer surge line break was eliminated. Following the application of LBB, the governing pipe breaks in the design basis of the reactor coolant system are the primary branch lines, including the safety injection accumulator and residual heat removal, and the main steam and feedwater piping attached to the steam generators.

The BVPS-1 plant-specific primary reactor coolant loop piping, piping components, replacement steam generators, reactor coolant pumps, and their supports were evaluated for the EPU and RSG conditions using a three-dimensional NUPIPE-SWPC model. The NUPIPE-SWPC computer code was used to perform the thermal, deadload, pressure, seismic and dynamic time history analyses. The dynamic time history analyses were based on the branch line piping breaks and the main steam and feedwater piping breaks. Changes between the original analyses and the analyses in support of the EPU and the RSGs are:

1) The original primary reactor coolant loop piping system mathematical model was converted from the STARDYNE computer code format to the NUPIPE-SWPC computer code input format,
2) The ASME Code Case N-411 damping values, approved for use at BVPS-1, were used in lieu of 2% damping for the Design Basis Earthquake, and
3) The pipe break loadings were based on EPU conditions with the RSG, instead of pre-uprate conditions with the original steam generators.

The modal superposition method with 1 percent of critical damping applied at each mode was used in the dynamic analyses, which is consistent with the BVPS-1 design basis for the primary reactor coolant loop piping systems. The resultant stresses for the reactor coolant loop piping have been determined, as shown in EPU Licensing Report Table 8.3-1. The calculated stresses are less than the code allowable limits, and are therefore acceptable.

The results from the NUPIPE-SWPC analyses for the primary reactor coolant loop piping includes loads on the major components, nozzles, and supports for the normal operating conditions, upset conditions and the faulted LOCA conditions. These loads were used in the evaluations of the major components, nozzles, and supports (including the replacement steam generators, reactor coolant pumps, and reactor vessel) and have been shown to be acceptable. The component support loads, with consideration for EPU and RSG are less with the application of LBB than those in the original design basis analyses; therefore, the existing analyses stress values are bounding, are within the code allowable limits, and are acceptable. Since the component loading are less than the existing loads the component supports were not re-analyzed to develop new maximum stress values.

The stresses and CUFs provided for BVPS-1 piping, components and supports, including the RV and internals, at the EPU conditions include the dynamic effect of the replacement SGs.

The component nozzle loads were reconciled with the final loop stress analysis that included the Replacement Steam Generators. The values reported for the nozzle loads in the licensing report are bounding except for the reactor coolant pump nozzle loads reported in Table 4.6.1-2A. The nozzle loads increased slightly as shown below;

	Maximum Upset Stress Intensity (psi)	
RCP Component	**Table 4.6.1-2A (original)**	**Reconciled**
Discharge Nozzle	[ ]a,c	[ ]a,c
Suction Nozzle	[ ]a,c	[ ]a,c
Casing	[ ]a,c	[ ]a,c
Note: Westinghouse Proprietary Information (provided as separate enclosure (a,c)		

The evaluations used existing design basis information, as stated in the EPU License Report, to assess the impact of EPU conditions, including the fatigue analyses (CUF evaluations). Fatigue analyses were not performed on those piping, components and supports for which the existing design basis did not require a fatigue analysis.

L-05-078 Enclosure 3

March 11, 2005 RAI Question LAR Applicability

On October 4, 2004 FirstEnergy Nuclear Operating Company (FENOC) submitted license amendment request (LAR) 302 and 173 by letter L-04-125. This submittal requested an Extended Power Uprate (EPU) for Beaver Valley Power Station (BVPS) Unit Nos. 1 and 2.

On April 13, 2005 FENOC submitted LAR 320 by letter L-05-069. This LAR is known as the replacement steam generator (RSG) LAR. The RSG LAR contains the technical specification changes proposed in the EPU LAR that are needed to replace the BVPS Unit No. 1 steam generators and to credit the safety analyses at 2900 MWt.

The following table identifies the LAR applicability of the March 11, 2005 RAI questions. A table entry of "EPU" means that the question is applicable to the EPU LAR. A table entry of "RSG & EPU" means that the question is applicable to both the EPU and RSG LAR.

RAI Question LAR Applicability					
No.	**LAR**	**No.**	**LAR**	**No.**	**LAR**
A.1	EPU	H.1	EPU	K.1	EPU
A.2	EPU	H.2	EPU	K.2	EPU
		H.3	EPU	K.3	EPU
B.1	EPU	H.4	EPU		
B.2	EPU	H.5	EPU	L.1	EPU
B.3	EPU	H.6	EPU	L.2	EPU
B.4	EPU	H.7	EPU	L.3	EPU
		H.8	EPU	L.4	EPU
C.1	RSG & EPU	H.9	EPU	L.5	EPU
		H.10	EPU		
D.1	EPU	H.11	RSG & EPU	M.1	EPU
		H.12	RSG & EPU	M.2	RSG & EPU
E.1	EPU			M.3	EPU
E.2	EPU	I.1	EPU	M.4	EPU
E.3	EPU	I.2	RSG & EPU		
E.4	EPU	I.3	RSG & EPU	N.1	EPU
		I.4	RSG & EPU	N.2	EPU
F.1	EPU	I.5	RSG & EPU	N.3	EPU
F.2	EPU			N.4	EPU
F.3	EPU	J.1	EPU	N.5	RSG & EPU
F.4	EPU	J.2	EPU	N.6	EPU
		J.3	EPU	N.7	EPU
G.1	EPU	J.4	EPU	N.8	EPU
G.2	EPU	J.5	EPU	N.9	EPU
G.3	EPU	J.6	EPU	N.10	EPU
G.4	EPU	J.7	EPU	N.11	EPU
		J.8	EPU	N.12	EPU
		J.9	EPU	N.13	EPU
				N.14	EPU

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Our ref: CAW-05-1999

May 26, 2005

APPLICATION FOR WITHHOLDING PROPRIETARY
INFORMATION FROM PUBLIC DISCLOSURE

Subject: Responses to NRC RAI N.2, "BVPS Reactor Vessel Internals Calculated Stress Values for Flow Induced Vibration" (Proprietary) and NRC RAI N.4, "BVPS Reactor Coolant Pump Component Maximum Upset Stress Intensities" (Proprietary)

The proprietary information for which withholding is being requested in the above-referenced report is further identified in Affidavit CAW-05-1999 signed by the owner of the proprietary information, Westinghouse Electric Company LLC. The affidavit, which accompanies this letter, sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b)(4) of 10 CFR Section 2.390 of the Commission's regulations.

Accordingly, this letter authorizes the utilization of the accompanying affidavit by FirstEnergy Nuclear Operating Company.

Correspondence with respect to the proprietary aspects of the application for withholding or the Westinghouse affidavit should reference this letter, CAW-05-1999, and should be addressed to J. A. Gresham, Manager, Regulatory Compliance and Plant Licensing, Westinghouse Electric Company LLC, P.O. Box 355, Pittsburgh, Pennsylvania 15230-0355.

Very truly yours,

J. A. Gresham, Manager
Regulatory Compliance and Plant Licensing

Enclosures

cc: B. Benney
L. Feizollahi

bcc: J. A. Gresham (ECE 4-7A) 1L
R. Bastien, 1L (Nivelles, Belgium)
C. Brinkman, 1L (Westinghouse Electric Co., 12300 Twinbrook Parkway, Suite 330, Rockville, MD 20852)
RCPL Administrative Aide (ECE 4-7A) 1L, 1A (letter and affidavit only)
J. J. DeBlasio
R. Surman

CAW-05-1999

AFFIDAVIT

COMMONWEALTH OF PENNSYLVANIA:

ss

COUNTY OF ALLEGHENY:

Before me, the undersigned authority, personally appeared J. A. Gresham, who, being by me duly sworn according to law, deposes and says that he is authorized to execute this Affidavit on behalf of Westinghouse Electric Company LLC (Westinghouse), and that the averments of fact set forth in this Affidavit are true and correct to the best of his knowledge, information, and belief:

J. A. Gresham, Manager
Regulatory Compliance and Plant Licensing

Sworn to and subscribed
before me this 26th day
of May, 2005

Margaret L. Gonano
Notary Public

Notarial Seal
Margaret L. Gonano, Notary Public
Monroeville Boro, Allegheny County
My Commission Expires Jan. 3, 2006

Member, Pennsylvania Association Of Notaries

(1) I am Manager, Regulatory Compliance and Plant Licensing, in Nuclear Services, Westinghouse Electric Company LLC (Westinghouse), and as such, I have been specifically delegated the function of reviewing the proprietary information sought to be withheld from public disclosure in connection with nuclear power plant licensing and rule making proceedings, and am authorized to apply for its withholding on behalf of Westinghouse.

(2) I am making this Affidavit in conformance with the provisions of 10 CFR Section 2.390 of the Commission's regulations and in conjunction with the Westinghouse "Application for Withholding" accompanying this Affidavit.

(3) I have personal knowledge of the criteria and procedures utilized by Westinghouse in designating information as a trade secret, privileged or as confidential commercial or financial information.

(4) Pursuant to the provisions of paragraph (b)(4) of Section 2.390 of the Commission's regulations, the following is furnished for consideration by the Commission in determining whether the information sought to be withheld from public disclosure should be withheld.

(i) The information sought to be withheld from public disclosure is owned and has been held in confidence by Westinghouse.

(ii) The information is of a type customarily held in confidence by Westinghouse and not customarily disclosed to the public. Westinghouse has a rational basis for determining the types of information customarily held in confidence by it and, in that connection, utilizes a system to determine when and whether to hold certain types of information in confidence. The application of that system and the substance of that system constitutes Westinghouse policy and provides the rational basis required.

Under that system, information is held in confidence if it falls in one or more of several types, the release of which might result in the loss of an existing or potential competitive advantage, as follows:

(a) The information reveals the distinguishing aspects of a process (or component, structure, tool, method, etc.) where prevention of its use by any of Westinghouse's competitors without license from Westinghouse constitutes a competitive economic advantage over other companies.

(b) It consists of supporting data, including test data, relative to a process (or component, structure, tool, method, etc.), the application of which data secures a competitive economic advantage, e.g., by optimization or improved marketability.

(c) Its use by a competitor would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing a similar product.

(d) It reveals cost or price information, production capacities, budget levels, or commercial strategies of Westinghouse, its customers or suppliers.

(e) It reveals aspects of past, present, or future Westinghouse or customer funded development plans and programs of potential commercial value to Westinghouse.

(f) It contains patentable ideas, for which patent protection may be desirable.

There are sound policy reasons behind the Westinghouse system which include the following:

(a) The use of such information by Westinghouse gives Westinghouse a competitive advantage over its competitors. It is, therefore, withheld from disclosure to protect the Westinghouse competitive position.

(b) It is information that is marketable in many ways. The extent to which such information is available to competitors diminishes the Westinghouse ability to sell products and services involving the use of the information.

(c) Use by our competitor would put Westinghouse at a competitive disadvantage by reducing his expenditure of resources at our expense.

(d) Each component of proprietary information pertinent to a particular competitive advantage is potentially as valuable as the total competitive advantage. If competitors acquire components of proprietary information, any one component may be the key to the entire puzzle, thereby depriving Westinghouse of a competitive advantage.

(e) Unrestricted disclosure would jeopardize the position of prominence of Westinghouse in the world market, and thereby give a market advantage to the competition of those countries.

(f) The Westinghouse capacity to invest corporate assets in research and development depends upon the success in obtaining and maintaining a competitive advantage.

(iii) The information is being transmitted to the Commission in confidence and, under the provisions of 10 CFR Section 2.390, it is to be received in confidence by the Commission.

(iv) The information sought to be protected is not available in public sources or available information has not been previously employed in the same original manner or method to the best of our knowledge and belief.

(v) The proprietary information sought to be withheld in this submittal is that which is appropriately marked in "brackets" in EPU RAI N.2 Response, "BVPS Reactor Vessel Internals Calculated Stress Values for Flow Induced Vibration" (Proprietary) and EPU RAI N.4 Response, "BVPS Reactor Coolant Pump Component Maximum Upset Stress Intensities" (Proprietary) dated May 26, 2005, for Beaver Valley Power Station, being transmitted by the FirstEnergy Nuclear Operating Company FENOC letter and Application for Withholding Proprietary Information from Public Disclosure, to the Document Control Desk. The proprietary information as submitted by Westinghouse for the Beaver Valley Units 1 and 2 is expected to be applicable for other licensee submittals in response to certain NRC requirements for justification of Flow Induced vibration for EPU conditions.

This information is part of that which will enable Westinghouse to:

(a) Provide documentation of the actual margins relative to the calculated stresses.

(b) Assist the customer in obtaining NRC approval by responding to NRC.

Further this information has substantial commercial value as follows:

(a) Westinghouse plans to sell the use of similar information to its customers for purposes of Flow Induced Vibration (FIV) assessments and RCP Component Maximum Upset Stress Intensities at EPU conditions.

(b) Its use by a competitor would reduce his expenditure of resources or improve his competitive position in the design and licensing a similar product.

(c) The information requested to be withheld reveals the distinguishing aspects of a methodology which was developed by Westinghouse.

Public disclosure of this proprietary information is likely to cause substantial harm to the competitive position of Westinghouse because it would enhance the ability of competitors to provide similar calculations and licensing defense services for commercial power reactors without commensurate expenses. Also, public disclosure of the information would enable others to use the information to meet NRC requirements for licensing documentation without purchasing the right to use the information.

The development of the technology described in part by the information is the result of applying the results of many years of experience in an intensive Westinghouse effort and the expenditure of a considerable sum of money.

In order for competitors of Westinghouse to duplicate this information, similar technical programs would have to be performed and a significant manpower effort, having the requisite talent and experience, would have to be expended.

Further the deponent sayeth not.

PROPRIETARY INFORMATION NOTICE

Transmitted herewith are proprietary and/or non-proprietary versions of documents furnished to the NRC in connection with requests for generic and/or plant-specific review and approval.

In order to conform to the requirements of 10 CFR 2.390 of the Commission's regulations concerning the protection of proprietary information so submitted to the NRC, the information which is proprietary in the proprietary versions is contained within brackets, and where the proprietary information has been deleted in the non-proprietary versions, only the brackets remain (the information that was contained within the brackets in the proprietary versions having been deleted). The justification for claiming the information so designated as proprietary is indicated in both versions by means of lower case letters (a) through (f) located as a superscript immediately following the brackets enclosing each item of information being identified as proprietary or in the margin opposite such information. These lower case letters refer to the types of information Westinghouse customarily holds in confidence identified in Sections (4)(ii)(a) through (4)(ii)(f) of the affidavit accompanying this transmittal pursuant to 10 CFR 2.390(b)(1).

FirstEnergy Nuclear Operating Company

Letter for Transmittal to the NRC

The following paragraphs should be included in your letter to the NRC:

Enclosed are:

1. 4 copies of RAI Response N.2, "BVPS Reactor Vessel Internals Calculated Stress Values for Flow Induced Vibration" (Proprietary) and RAI Response N.4, "BVPS Reactor Coolant Pump Component Maximum Upset Stress Intensities" (Proprietary)

2. 2 copies of RAI Response N.2, "BVPS Reactor Vessel Internals Calculated Stress Values for Flow Induced Vibration" (Non-proprietary) and RAI Response N.4, "BVPS Reactor Coolant Pump Component Maximum Upset Stress Intensities" (Non-proprietary)

Also enclosed is Westinghouse authorization letter CAW-05-1999 with accompanying affidavit, Proprietary Information Notice, and Copyright Notice.

As Item 1 contains information proprietary to Westinghouse Electric Company LLC, it is supported by an affidavit signed by Westinghouse, the owner of the information. The affidavit sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b) (4) of Section 2.390 of the Commission's' regulations.

Accordingly, it is respectfully requested that the information which is proprietary to Westinghouse be withheld from public disclosure in accordance with 10 CFR Section 2.390 of the Commission's regulations.

Correspondence with respect to the copyright or proprietary aspects of the items listed above or the supporting Westinghouse affidavit should reference CAW-05-1999 and should be addressed to J. A. Gresham, Manager, Regulatory Compliance and Plant Licensing, Westinghouse Electric Company LLC, P.O. Box 355, Pittsburgh, Pennsylvania 15230-0355.