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July 28, 2005
L-05-130

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 (RAI dated June 30, 2005) in Support of License Amendment Request Nos. 302 and 173

By letter dated June 30, 2005, the U.S. Nuclear Regulatory Commission (NRC) issued a request for additional information (RAI) pertaining to FirstEnergy Nuclear Operating Company (FENOC) License Amendment Request (LAR) Nos. 302 and 173 (Reference 1). These LARs propose an Extended Power Uprate (EPU) for Beaver Valley Power Station (BVPS) Unit Nos. 1 and 2. The EPU LAR proposes increasing the licensed power level approximately 8 percent above the current licensed power level.

Attachment A contains the FENOC responses to the June 30, 2005 RAI questions. 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.

Reference 2 transmitted FENOC LAR 320, which is known as the replacement steam generator (RSG) LAR. The RSG LAR contains those Technical Specification changes originally proposed in the EPU LAR that are needed to replace the BVPS Unit No. 1 steam generators. Since approval of the RSG LAR is expected well before approval of the EPU LAR, an effort has been made to identify the questions in Attachment A that also apply to the RSG LAR. To aid the EPU and RSG LAR reviewers, the LAR applicability for each question is noted in Attachment A.

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.

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I declare under penalty of perjury that the foregoing is true and correct. Executed on July 28, 2005.

Sincerely,

Thomas S. Cosgrove

Attachment:
A. Responses to RAIs dated June 30, 2005

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 Senior Resident Inspector
Mr. S. J. Collins, NRC Region I Administrator
Mr. D. A. Allard, Director BRP/DEP
Mr. L. E. Ryan (BRP/DEP)

L-05-130 ATTACHMENT A

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION (RAI)

RELATED TO FIRSTENERGY NUCLEAR OPERATING COMPANY (FENOC)

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

EXTENDED POWER UPRATE (EPU)

DOCKET NOS. 50-334 AND 50-412

By letter dated October 4, 2004, as supplemented by letters dated February 23, May 26, and June 14, 2005, Agencywide Documents Access and Management System (ADAMS) Accession Nos. ML042920300, ML051160426, ML051160429, ML051160431, ML51530376, and ML051670270, FENOC (licensee) proposed changes to BVPS-1 and 2 operating licenses to increase the maximum authorized power level from 2689 to 2900 megawatts thermal (MWt) rated thermal power (RTP) or approximately 8%. The Nuclear Regulatory Commission (NRC) staff has reviewed the licensee's application against the guidelines in the EPU review standard, RS-001, Revision 0, "Review Standard for Extended Power Uprates," December 2003, and determined that it will need the additional information identified below to complete its review.

Part A - February 23, 2005, Supplement, Attachment B, Environmental Considerations

A.1 Question (Applicable to EPU)

The supplemental information provided states that operation of BVPS-1 and 2 at the fully uprated power level of 2900 MWt would increase evaporation rates from the cooling towers by approximately 10%. The supplement discussed the resultant anticipated increase in consumptive losses from the Ohio River. The NRC staff needs additional information regarding the following potential impacts of cooling system operation at EPU conditions:

a. Provide information regarding cooling tower plume impacts, including consideration of impacts on fogging and icing potential attributable to the plume.

Response:

Based on a review of the original predictions of the potential for fogging and icing from the two BVPS cooling tower plumes, including a maximum of approximately 10% of additional EPU heat released by the cooling towers during operation, the cooling tower impacts are as follows:

1. The wide dispersion and elevated cooling tower exhaust plumes of the natural draft towers at BVPS provide an inherent advantage in mitigating any fogging and icing potentials. The inherent advantage is not impacted by EPU conditions.

2. The fogging potential of the cooling tower plumes is slightly diminished compared to the existing plume trajectories. The EPU higher heat load will increase the tower exit velocity and temperature. The plumes will be more buoyant and have a slightly higher upward

velocity. Thus the plumes will be even further from touching the ground and causing fogging than the 250-ft elevation indicated by the plume studies in the original station BVPS Unit 2 Updated Final Safety Analysis Report (UFSAR), Section 2.3.2, which considered both BVPS-1 and BVPS-2 cooling towers.

3. The icing potential of the plumes during EPU operation may increase slightly, estimated as a maximum of approximately 8% more than indicated by the plume studies of the original station BVPS-2 UFSAR Section 2.3.2. This is an additional thickness of 0.002 inches compared to the original icing estimates. It was noted that the original icing estimates were based on very high drift rates and depositions that likely have not actually occurred during the past 28 years of the operation of the Beaver Valley Power Station.

b. The increased consumptive use results in a decrease in cooling tower basin blowdown flow. Provide analysis of the impact of this decrease on cooling tower basin water quality, including changes in the quality of blowdown discharge to the Ohio River and the potential for increased cooling tower basin sedimentation and related solid waste disposal impacts.

Response:

The increased plant load due to EPU will increase the cooling tower (CT) blowdown discharge temperature to the Ohio River approximately 3°F. The CT evaporation rate will increase up to an additional 10% which will reduce CT blowdown flow, concentrate solutions and suspensions in the discharged water, and yield up to 10% more solids deposition in the cooling towers. The analysis of these impacts on the CT basin water quality and solid waste generation is as follows:

- National Pollutants Discharge Elimination System (NPDES) Permit No. PA0025615, Part C.10 specifies that the discharge may not change the temperature of the receiving stream by more than 2°F in any one hour. The data evaluated indicates that the post-EPU discharges will not challenge this NPDES permit parameter.
- No additional chemical usage is planned as a result of operation at EPU conditions. No additional pumps to increase water usage will be added. Therefore, total chemical mass and concentration in the service and river water systems will not be changed, and the chemical mass in the circulating water system will not be changed.
- The additional evaporation related to operation at EPU conditions will not cause the mass or concentration parameters to exceed the BVPS NPDES permit (No. PA0025615) parameter limits.
- In the worst-case scenario, the additional evaporation could concentrate suspended solids up to 10% more in CT blowdown. This additional 10% increase in suspended solids will not cause measurable or significant impacts to Ohio River quality. It is expected, however, that some of the additional solids will settle into the cooling tower basins, and not be discharged to the river via blowdown.
- There is thus a potential for up to 10% more sedimentation in the cooling tower basins because of EPU. This sedimentation is removed from the cooling towers during refueling outages, but FENOC does not dispose of the BVPS materials as solid waste. In Pennsylvania (PA), if the removed materials are disposed of as waste, then it is regulated as PA Residual Waste. The removed materials, however, are not managed or classified as

waste at BVPS. The materials are applied to BVPS property in accordance with the Land Recycling Acts and programs, and the Pennsylvania Department of Environmental Protection (PA DEP) Clean Fill Use Policy. Therefore, no additional waste will be generated due to operation at EPU conditions, and the expected additional sediment will be beneficially used.

- Consideration was given to changes in steam generator blowdown demineralizer waste resin generation. The approximate annual waste resin (classified as Residual Waste in Pennsylvania) generation is 50,000 pounds from BVPS-1, and 37,000 pounds from BVPS-2. Since operation at EPU conditions will not increase the steam generator blowdown, no significant additional solid waste resin will be generated.

Based on the above, the effects of the increased evaporation on cooling tower blowdown will not cause significant environmental and water quality impacts to the Ohio River and solid waste disposal is not impacted. The EPU will not invalidate NRC's conclusions in the BVPS Final Environmental Statements.

A.2 Question (Applicable to EPU)

Describe any changes in chemical usage planned to support the EPU, if any, affecting NPDES permitted discharges and/or solid waste generation.

Response:

No additional chemical usage is planned as a result of the EPU. No additional pumps to increase water usage will be added. Therefore, total chemical mass in the service, river, and circulating water systems will not be changed. As discussed above, the NPDES-permitted discharges and/or solid waste generation will not be exceeded. The EPU will not invalidate NRC's conclusions in the BVPS Final Environmental Statements.

A.3 Question (Applicable to EPU)

Describe any changes in the number of operating personnel required to support normal operations and outages as a result of the EPU.

Response:

As a result of the proposed EPU, plant radioactive source terms are anticipated to increase proportional to the actual power level increase. This is expected to result in a small increase in liquid, gaseous and solid radioactive waste generation.

The site employs plant support personnel outside of the on-shift operational staff to address solid radioactive waste management. The on-shift operations staff, in conjunction with plant support personnel, manages all planned liquid and gaseous discharges. These resources will continue and are adequate to support any increase in anticipated radioactive waste management activities following implementation of EPU.

During a refueling outage, the time associated with refueling activities may increase slightly due to the anticipated increase in the number of new fuel assemblies associated with operation at EPU conditions. The small increase in work time is anticipated to be managed by the assigned refueling team without the need for additional staff.

No other changes are planned or anticipated at EPU conditions that would require additional staff. Minimum on-shift staffing requirements as defined in Technical Specifications will continue to support plant operation. Therefore, FENOC has no plans to add additional staff at BVPS to support normal operations and outages as a result of the proposed EPU.

A.4 Question (Applicable to EPU)

Confirm that non-radioactive air emissions attributable to the on-site auxiliary boilers, diesel generators, and diesel fire pump would be unaffected by EPU operating conditions and will remain less than those requiring a prevention-of-significant-deterioration analysis, as discussed in the Final Environmental Statement related to the operation of BVPS-2.

Response:

Emissions from the fossil fuel used in the auxiliary boilers, the emergency diesel generators (EDG), and the diesel fire pump were evaluated for the impacts related to the EPU, and are summarized below.

<u>Auxiliary Boilers</u>

The EPU will not increase the need for additional auxiliary steam at BVPS. The EPU will also not lead to an increased frequency of auxiliary boiler routine testing. Therefore, there is no increase in fuel usage emissions as a result of the EPU.

<u>Emergency Diesel Generators</u>

An EPU loading analyses confirmed that the existing Emergency Diesel Generators (EDG) are adequately sized to support unit operation at EPU conditions. Refer to RAI response C.4 for discussion on EDG loading impact. The rated horsepower of the EDGs will not be increased as a result of the EPU. The existing operating surveillance tests that periodically operate the EDGs will not be changed as a result of EPU, and there will be no increase in EDG emissions during periodic test runs. Therefore, the maximum emissions previously reported in the BVPS Final Environmental Statements will also not be affected by the EPU.

<u>Diesel Fire Pump</u>

The EPU will not impact the required fire protection flow requirements, and the EPU will not increase the need for operation or testing of the diesel fire pump. Therefore, there is no increase in fuel usage emissions as a result of EPU.

The EPU will not affect non-radiological air emissions from the auxiliary boilers, the emergency diesel generators, or the diesel fire pump because there will be no increase in fuel oil consumption or operating time. All of these components were identified in Section 5.4.2 of the Final Environmental Statement (FES) related to the operation of Beaver Valley Power Station, Unit 2, dated September 1985. Although this document is for BVPS-2, Section 5.4.2 also addresses BVPS-1 because 'Other Emissions' were not specifically addressed in the original BVPS-1 FES.

Therefore, the conclusions of the FES, Section 5.4.2, remain valid for operation at EPU conditions.

A.5 Question (Applicable to EPU)

Describe any fuel cycle impacts. Does the EPU have any effect on the refueling cycle length or number of fuel elements to be discharged each operating cycle?

Response:

Both BVPS units will maintain their nominal 18-month refueling cycle with the EPU. The increased power level of the EPU will require additional energy for each cycle. To accommodate this extra energy, it is expected that additional fresh feed fuel assemblies will be needed in the core designs. The specific number of feed assemblies (and, therefore, discharge assemblies) for each cycle will be determined during the core design process, based on specific startup and shutdown dates for the cycle, and expected energy carryover from the previous cycle. A review has identified that four additional fresh fuel assemblies will be needed, nominally, under EPU conditions to meet the higher energy needs.

Part B - Plant Systems

B.1 Question (Applicable to EPU)

Section 9.9 of the "Beaver Valley Power Station Extended Power Uprate Licensing Report" (Enclosure 2 of the licensee's October 4, 2004 license amendment request), addresses the impact of EPU on fuel pool cooling and purification systems. In Section 9.9, it is concluded that normal and abnormal fuel pool temperature limits are not exceeded based on the fact that EPU considerations were included in the evaluation submitted in a previous licensing action request (LAR) that the NRC reviewed and approved in the safety evaluation (SE) enclosed with Amendment Nos. 247 and 126, dated January 29, 2002, for BVPS-1 and 2, respectively. In Section 3.1.2 of the referenced SE, it is stated that "The licensee also has committed to administratively control the offloading of fuel based on the CCW [component cooling water] temperature and decay time." This commitment was included as Attachment E to your FENOC letter, dated October 21, 2001, ADAMS Accession No. ML020300051. In reviewing the Updated Final Safety Analysis Reports (UFSARs) for BVPS-1 and 2, the NRC staff found the commitment to administratively control the offloading of fuel based on CCW temperature and decay time present only in the BVPS-2 UFSAR. Please explain why a discussion consistent with the commitment that was made is not included in the BVPS-1 UFSAR, and confirm that the commitment to implement administrative controls for the BVPS-1 fuel pool is being met and will continue to be applicable for the uprated plant.

Response:

During implementation of License Amendment 247 for BVPS-1 and License Amendment 126 for BVPS-2, the BVPS Corrective Action Program included actions for implementing the subject commitments to include administrative controls for ensuring acceptable fuel pool temperature by controlling offloading of fuel based on component cooling water temperature and decay time.

These administrative controls were incorporated into operations surveillance procedures 1OST-49.3, "Refueling Procedure Prerequisites" and 2OST-49.3, "Refueling Procedure Prerequisites" in March 2002. These operations surveillance procedures provide steps for determining if Component Cooling Water (CCW) temperature is adequate to support movement of irradiated fuel assemblies from the reactor core prior to fuel movement. The steps in the BVPS-1 and BVPS-2 procedures are clearly identified as "commitments" with a noted subscript next to the step identifying the origin of the commitment. As such, the commitment can not be changed or omitted without going through the established, rigorous site commitment change process. Therefore, the commitments to implement administrative controls for the BVPS-1 and BVPS-2 fuel pools are presently being met and will continue to be applicable for the EPU conditions.

In addition to the administrative controls incorporated into the operations surveillance procedures, the BVPS-2 UFSAR Section 9.1.3.3 was revised to include the following: "Administrative controls ensure acceptable fuel pool temperature by controlling offloading of fuel based on component cooling water temperature and decay time (refer to License Amendment No. 126 of the BVPS-2 Technical Specifications)." A similar statement was not included in the BVPS-1 UFSAR due to an administrative oversight.

To maintain consistency between the two UFSARs, wording similar to what appears in the BVPS-2 UFSAR will be included in the BVPS-1 UFSAR. This action to update the BVPS-1 UFSAR is being tracked by the BVPS Corrective Action Program.

B.2 Question (Applicable to EPU)

Section 10.12 of Enclosure 2 of the October 4, 2004, license amendment request addresses flood protection. In particular, it addresses the flood levels inside the containment for BVPS-1 and BVPS-2. It also discusses protection that is afforded for the two units against the effects of external flooding. However, flooding outside containment due to high-energy line breaks and moderate-energy line breaks are not addressed. Please discuss what impact EPU will have on the existing flooding analysis in this regard. Also, please discuss any additional impact that postulated pipe failures (i.e., breaks and cracks) will have on systems and components important to safety as a result of the proposed EPU.

Response:

The proposed EPU will have no impact on the existing analysis for flooding outside containment due to high-energy line breaks and moderate-energy line breaks. A review of the High Energy Line Breaks (HELB) for those lines subject to ruptures and Moderate Energy Pipe Cracks (MEPC) for those lines subject to cracks was performed. This review considered those lines routed in the proximity of systems and components important to safety at each unit. The mass and energy releases for the postulated HELB remain within analyzed conditions, and therefore, there will be no impact on the spray or jet impingement analyses of the affected area. For areas where MEPCs are identified as the limiting break, there would be no resulting spray or jet impingement effects.

<u>BVPS-1</u>

There are four areas at BVPS-1 containing either safety related mitigation or Class 1E electrical components outside containment that are subject to pipe breaks or cracks. The effects of the postulated breaks are summarized below.

Service Building

The limiting break is a circumferential break, HELB of a main feedwater line on elevation 752', which resulted in 3.6 inches of flooding to the levels below. The Class 1E electrical busses in those areas on elevation 713' are protected by 6 inch curbs. The EPU will increase the flow through the Main Feedwater System. However, that increase has only a minimal impact (less than 5%) on the discharge flow following a postulated feedwater line rupture. Thus, the additional water discharged will not result in a flood height above the installed curbs and the Class 1E busses will not be challenged.

Cable Vaults/Safeguards

The limiting break in this area (which, at BVPS-1, is a combination of the cable vaults and the Safeguards pipe tunnel areas) is a HELB of a 2-inch Auxiliary Steam Line located in the Safeguards pipe tunnel, which results in 4.9 inches of flooding at elevation 722. The geometry of the area (height of safety related equipment) precludes any flooding effects from such a break, since all vulnerable Class 1E equipment is located at least 12 inches above the floor. The capacity and maximum pressure of the Blowdown System is unaffected by the uprate; therefore, the existing flooding analysis remains valid since discharge from a postulated break will not change.

Auxiliary Building

The limiting failure is a Moderate Energy Pipe Crack (MEPC) of the Primary Plant Component Cooling Water (CCR) System. According to UFSAR Section 9.4.3.1, such a crack results in the maximum flood height at the 735' elevation of the BVPS-1 Auxiliary Building. The BVPS-1 Charging Pump Cubicles are pits sealed from floods on the elevation below; however, they are accessed by hatches on the 735' elevation. These hatches were designed with 14-inch high curbs to ensure that water from the postulated maximum flood could not enter the hatch openings. The existing capacity of the CCR system is sufficient to accommodate the increased heat loads resulting from the EPU. Therefore, the CCR flows are the same as the maximum design flows assumed for the flooding analysis, and the EPU will have no effect on this scenario.

Intake Structure

Internal floods in the cubicles housing the safety related BVPS-1 River Water Pumps was defined as a result of a BVPS event. The limiting break was analyzed and determined to be a rupture of a rubber expansion joint in a River Water Pump cubicle, which would only be isolated by operator action after 30 minutes. Such a rupture would completely flood out and disable the affected pump. However, the internal flood doors between cubicles are administratively kept closed which limits the flood height in the adjacent pump cubicle to 3 inches, well below the 12 inch minimum elevation above the floor of any vulnerable Class 1E electrical equipment. Therefore, since the pump flow requirements located in the intake structure remain unchanged for EPU conditions, the flooding analysis for the intake structure is unaffected.

BVPS-2

Section 3.6B.1.3.2.4 of the BVPS-2 UFSAR evaluated the High Energy Line Breaks (HELB) and Moderate Energy Pipe Cracks (MEPC) that could affect safety related equipment located outside containment at BVPS-2. The effects of the postulated breaks are summarized below.

Service Building

The only safety related equipment in the Service Building itself are the Class 1E Electrical busses located on the 730' elevation. The water from the postulated Main Feedwater line HELB on elevation 780' would drain down to this floor; however, all the Class 1E buses are located above the flood height. The impact of the EPU on main feedwater flow will not affect the maximum postulated HELB discharge flow.

Cable Vaults

The source of the highest flood level at elevation 718 feet-6 inches is a moderate energy crack in an 18-inch Primary Plant Component Cooling (CCP) line. All safety-related valves and electrical/control equipment are located above this highest flood level. Safety-related, redundant, Class 1E level instruments are located in the sump at elevation 718 feet-6 inches to alarm in the control room at high level.

The highest flood level at elevation 735 feet-6 inches is due to a MEPC in a 4-inch diameter fire water line. At elevation 755 feet-6 inches, water from the Main Feedwater HELB in the Service Building drains via a stairwell to lower elevations. The fire protection water lines in the alternate shutdown panel room at elevation 755 feet-6 inches have been crack excluded so no flooding potential exists in this area.

The EPU has no effect on the maximum design conditions of the CCP system, therefore flooding resulting from the postulated MEPC of that system is unaffected. The fire protection system is not impacted by the EPU.

Main Steam Valve Area

This area contains safety-related components required for steam and feedwater isolation, which are located at elevation 773 feet-6 inches. The source of the highest flood level in this area is a MEPC in a 4-inch service water line. All safety related equipment in this area is above the flood level. The flooding from the Service Water System (SWS) is not affected by the EPU since the SWS is unaffected by the EPU.

Other small diameter lines in the area could be subject to a HELB for which breaks are postulated resulting in steam release. No significant flood levels are experienced from any of these breaks since the steam release to the cubicle results in a pressure increase and a major portion of the released mass is vented through openings in the cubicle to reduce pressure. The EPU does not change the thermohydraulic results of such breaks, which by their nature do not result in flooding.

Safeguards Building

The Safeguards Building at elevation 718 feet-6 inches is separated into two separate areas, north and south, each containing the Low Head Safety Injection (LHSI), Quench Spray, and motor-driven Auxiliary Feedwater Pumps of one of the two redundant trains. These north and south areas include a sump which has a safety-related, Class 1E level instrument providing a high level alarm in the control room.

The source of the highest flood level in these pump cubicles is a MEPC in the Low Head Safety Injection (LHSI) pump suction line from the Refueling Water Storage Tank (RWST). The LHSI, quench spray, and auxiliary feedwater pumps in each area are located above the highest flood level.

Flooding in the recirculation spray pump areas was considered in two parts, above elevation 718 feet-6 inches where the pump motor is located, and below elevation 697 feet-6 inches where the pump suction valves are located. These two areas are hydraulically separate (that is, a flood in the upper area cannot reach the lower area). The source of the highest flood level in the upper area is a passive failure of a RSS line. Only one recirculation spray pump cubicle is affected by this failure due to the compartmental design of the pump cubicles. The pump motors are located well above the highest flood level.

The area in which the turbine-driven Auxiliary Feedwater Pump is located is subject to flooding from the LHSI suction line MEPC. This auxiliary feedwater pump is located well above the flood level. The EPU does not impact the maximum flow from the LHSI MEPC, since the crack flow is not dependent on maximum pump flow.

The safeguards building above elevation 738 feet-6 inches houses the hydrogen analyzers, safety-related air-conditioning units and safety-related Motor Control Centers (MCC). The source of maximum flooding in the air conditioning and MCC cubicles is a moderate energy pipe crack in the service water piping to the air-conditioning units. The air-conditioning units and MCC are located above the highest flood level. The flooding from the SWS is not affected by the EPU, therefore flooding results remain the same.

Auxiliary Building

The flooding analysis for the auxiliary building and cable vault areas considered a double ended rupture of the main feedwater line on elevation 780 feet-6 inches of the Service Building as the governing flooding condition. However, it was only necessary to consider a crack in this piping. For conservatism, however, the flood heights for a double-ended rupture event were considered.

Below elevation 735 feet-6 inches, the auxiliary building arrangement provides two separate areas that could be flooded independently of one another. A wall separates the portion of the building below elevation 735 feet-6 inches into a north and a south cubicle. Since most floods above this elevation will drain through floor grating, stairways, pipe chases, etc, to the lower cubicles, pipe/tank failures in the upper elevations were included in the flood analysis of these north and south cubicles. The source of the highest flood level in the north cubicle is a MEPC in a 36-inch diameter service water line on the 710-ft elevation. In the south cubicle, the source of the highest level is a double-ended rupture of a main feedwater line occurring on elevation 780 feet-6 inches of the Service building which then drains to the lower elevations of the Auxiliary Building.

The Charging/High Head Safety Injection (HHSI) pumps at BVPS-2 are located on the 735 feet-6 inches elevation. Any floods from a HELB or MEPC would drain to the lower levels of the Auxiliary Building and thus not affect the charging pumps.

Safety-related, Class 1E, redundant level instrumentation is provided in the sump in the south area of the Auxiliary Building to detect a high water level and alert the operator. High level alarms are provided in the control room. Since the north area could flood to above the dividing wall without affecting safety components, and once above the wall would spill into the south area and be detected, no instrumentation need be provided in the north area.

In a similar manner as described above for BVPS-1, the EPU effects on the Main Feedwater and Service Water Systems will not affect the limiting floods.

Intake Structure

The postulated piping failure at BVPS-2 that causes the highest flood level above the operating deck, is an MEPC in a 30-inch service water line. The service water pump motor in the affected cubicle would be submerged as a result of this break and rendered inoperable. However, three service water pumps are provided. The second pump in the connected adjacent cubicle would not be submerged because the connecting flood door is administratively kept closed and would limit the height of water. The third pump is located in a cubicle that is not connected to the pump cubicle where the MEPC is postulated and would thus be completely unaffected. One service water pump is sufficient to achieve shutdown conditions. Therefore, loss of one pump due to flooding has no adverse safety considerations. Since flooding from the Service Water System is not affected by the EPU, the flooding results remain the same.

B.3 Question (Applicable to EPU)

Section 8.1 of Enclosure 2 of the October 4, 2004, license amendment request states that "the turbine missile analyses for both BVPS-1 and BVPS-2 utilize probabilistic methodology." It also states that "these analyses demonstrate that the total turbine missile generation probabilities for BVPS-1 and BVPS-2 meet applicable acceptance criteria based on inspection and test interval programs for the turbines" and that current analyses are, therefore, bounding for EPU operation. Please provide the basis for the conclusion that the current analyses are bounding for the retrofitted turbine. Also, please discuss to what extent the existing turbine missile analyses for systems, structures, and components (SSCs) important to safety are affected by the proposed EPU (i.e., any additional SSCs that are within the zone of missile impact, missile impact energy and capability of affected SSCs to withstand postulated turbine missiles).

Response:

The existing BVPS-1 and BVPS-2 turbine missile generation analyses were redone in 2002 and the analyses remain bounding for EPU based on the following:

1. The high-pressure (HP) turbines are being replaced with ones with improved design margins, and as was the case for the original HP design, the design of the replacement HP turbine is not considered as a potential missile source.
2. The LP turbine discs are not being modified.
3. The normal operating speed and the overspeed trip setpoint are not being changed.
4. The design overspeed of 120% is not changed.
5. The inspection acceptance criteria and inspection intervals modeled in the missile analysis are not being changed.
6. The existing Original Equipment Manufacturer (OEM) LP turbine analysis was reviewed for the EPU conditions. The steam conditions shown on the new heat balances were converted into equivalent rotor disc temperatures and compared to the original temperatures used in the missile analysis for the LP rotors. The disc temperatures at EPU conditions were found to be equal to or less than the original disc temperatures.

EPU will have no effect on the existing missile analysis for BVPS-1 and 2. The existing OEM LP turbine analysis for BVPS-1 and 2 is judged to remain valid.

Based on the existing analyses being bounding for EPU, there are no new systems, structures, and components (SSCs) in the zone of missile impact, and there is no impact on the current systems, structures, and components important to safety.

B.4 Question (Applicable to EPU)

Section 8.1 of Enclosure 2 of the October 4, 2004, license amendment request addresses the impact of EPU on the main turbines, but there is no discussion of the impact of EPU on turbine overspeed protection capability. Please provide a discussion addressing to what extent the proposed EPU will affect the existing turbine overspeed protection capability, including a discussion of turbine overshoot during a loss of electrical load and supporting analyses that are credited, the effects of turbine modifications that will be completed, and post-modification testing that will be completed to confirm that the analytical results are correct.

Response:

As part of the EPU implementation, the high-pressure (HP) turbines are being replaced. The BVPS-1 HP turbine has already been replaced and the impact of the turbine overspeed protection capability has been addressed as part of the design change process.

The expected overspeed of the turbine upon loss of load (main generator breaker opening) at full uprate conditions was evaluated. It was calculated that this overspeed value is 5.0% above the speed at which the turbine trips. Based on a worst case overspeed trip at 111% the expected overspeed would be 116.0% of rated speed, which is below the design overspeed of 120%. However, the vendor calculated overspeed value of 5.0% did not account for the effect on turbine overspeed due to the entrained energy in the extraction steam lines upstream of the Non-Return Valves (NRV) or in the feedwater heaters that do not have a NRV.

A subsequent evaluation provided values for the effect on turbine overspeed due to entrained energy in the extraction steam system at full uprate conditions. These values were given in terms of % overspeed / volume of steam and/or water. A calculation was prepared using plant specific values for the volume of steam piping upstream of any NRV and water volume in any feedwater heater without an NRV. It was determined that even taking into account this additional extraction steam system energy, the turbine overspeed (118%) remains less than the design value of 120%.

The BVPS-2 HP turbine has not been replaced, as yet. BVPS-1 and BVPS-2 are similar turbine rotor sets. When the BVPS-2 HP turbine replacement is installed, the overspeed analysis will be performed as part of the design change process to determine the acceptability of the turbine overspeed protection. Based on the results of BVPS-1 analysis, the design value of 120% overspeed for BVPS-2 will remain bounding.

A station Operating Surveillance Test (OST) procedure verifies proper operation of the Turbine Overspeed Trip Protection Systems. The test is performed during station startup following a refueling outage and after any turbine maintenance that could affect the overspeed trip setpoint. The test demonstrates that the trip will occur at or below 111%. Testing to determine the expected overspeed / overshoot is not performed since this would require running the turbine above the normal operating speed at full load and creating an undesirable plant transient.

The Turbine Overspeed Protection System is demonstrated operable in accordance with the Licensing Requirements Manual (LRM) by performing the following:

- Cycling each of the turbine valves (throttle, governor, reheat stop, and reheat intercept) through at least one complete cycle from running position.
- Direct observation of the movement of each of the turbine valves (throttle, governor, reheat stop, and reheat intercept) through one complete cycle from running position.
- Channel Calibration of the turbine overspeed protection system.
- Inspection of the valve seats, disks, and stems and verifying no unacceptable flaws or excessive corrosion.

No additional post-modification testing of the turbine overspeed testing will be performed as part of the HP replacement and/or power ascension.

B.5 Question (Applicable to RSG and EPU)

Section 9.23 of Enclosure 2 of the October 4, 2004, license amendment request discusses the capability of the auxiliary feedwater (AFW) system to meet flow requirements for the uprated plant. The submittal indicates that a modification to install cavitating venturis is being made to the BVPS-1 AFW system and that as a result of this modification, two AFW pumps will now be required to meet the minimum flow requirements for a main feedwater line break and loss of normal feedwater events. The submittal indicates that the BVPS-1 UFSAR currently credits only one motor-driven AFW pump.

a. **Please describe the worst-case scenarios for the postulated main feedwater line break and loss of normal feedwater events, including single active failure considerations and how adequate flow is assured to the intact steam generators (as applicable). Also, please provide the flow requirements for the feedwater line break and loss of normal feedwater events for the uprated plant, along with the AFW system flow capability for both BVPS-1 and BVPS-2.**

Response:

The Auxiliary Feedwater Systems (AFW) at both BVPS-1 and BVPS-2 contain three pumps. Two of the pumps are motor-driven and supplied with electrical power from independent emergency power sources. The motor-driven feedwater pumps are nominally rated at 350 gpm. The third pump is a turbine-driven pump with a nominal rating of 700 gpm. Each pump is capable of delivering flow to all three steam generators. Technical Specification 3.7.1.2 requires all three AFW pumps to be operable.

The loss of normal feedwater event is described in Section 5.3.7 of the EPU Licensing Report. For this event, the limiting single failure is that of the turbine-driven auxiliary feedwater pump (the highest capacity AFW pump) which results in auxiliary feedwater flow from the two motor-driven pumps only. Auxiliary feedwater flow can be activated by steam generator low-low level signal, trip of both main feedwater pumps, a safety injection signal, or loss of feedwater in any two-out-of-three feedwater loops via the Anticipated Transient Without Scram (ATWS) Mitigating System Actuation Circuitry (AMSAC).

In the loss of normal feedwater analysis for the uprated plant, the required flow for BVPS-1 is 489 gpm total to all steam generators. The required flow for BVPS-2 is 400 gpm total to all steam generators. The BVPS-1 required flow is higher due to the lower steam generator low-low level trip setpoint which results in a lower feedwater inventory in the steam generators at the time of trip and a longer delay until the trip is activated. This setpoint is physically lower on BVPS-1 due to the lower elevation of the narrow range bottom level tap associated with the Model 54F steam generator.

The AFW system is capable of delivering a minimum of 489 gpm total flow to all steam generators at either BVPS-1 or BVPS-2 with minimum allowable pump performance (maximum allowable degradation) and a single failure of the turbine-driven auxiliary feedwater pump.

The feedwater line break event is described in Section 5.3.17 of the EPU Licensing Report. The limiting failure for this event is the failure of the highest capacity (the turbine-driven) AFW pump. The limiting case assumes a full double ended rupture of the main feedwater line between the last check valve and the steam generator. This results in a loss of main feedwater to all steam generators and loss of fluid from the affected steam generator. All other conservative assumptions are listed in Section 5.3.17 of the EPU Licensing Report. Auxiliary feedwater flow can be activated by steam generator low-low level signal, trip of both main feedwater pumps, or a safety injection signal.

Following the rupture of a main feedwater line, the emergency operating procedures direct the operator to isolate flow to the faulted steam generator. Prior to isolation, excessive flow to the faulted steam generator is prevented by cavitating venturis installed in the AFW piping. This prevents all AFW flow from being lost to the break prior to isolation. The AFW flows used in the feedwater line break analysis are 250 gpm to the intact steam generators prior to isolation of the faulted steam generator. An operator action time of 15 minutes is used to isolate the faulted steam generator. Following isolation, an AFW flow of 400 gpm to the intact steam generators is used.

The AFW system at either BVPS-1 or BVPS-2 is capable of supplying greater than 286 gpm to two intact steam generators during a feedwater line break prior to isolation of the faulted steam generator. The system can also supply greater than 440 gpm to two intact steam generators following isolation of the faulted steam generators. These flows are also based on the minimum allowable pump performance used for surveillance testing acceptance criteria and a failure of the turbine-driven AFW pump.

b. **For BVPS-1, it is necessary to credit an additional AFW pump that is not currently credited in the UFSAR for mitigating postulated feedwater line break events. In response 5.b (as provided in Attachment E of the February 23, 2005, EPU supplement), the licensee indicated that this is a change that requires NRC review and approval. However, the licensee has not adequately addressed and justified this change from a licensing-basis perspective and additional information must be provided in order to demonstrate that the proposed change is fully acceptable in this regard.**

Response:

As described above in the response to RAI Question B.5.a, the AFW system at BVPS-1 consists of three pumps. The limiting events with respect to AFW capacity are the loss of normal feedwater and main feedwater line break. The most limiting single failure for both events is the loss of the highest capacity AFW pump, which is the turbine-driven pump. The current licensing basis at BVPS-1 credits only one motor-driven feedwater pump for these events. This is primarily due to the fact that only one motor-driven feedwater pump is required to meet the flow requirements. BVPS-1 did not have flow limiting devices such that for single pump operation during a feedwater line break, the pump could have been challenged during the runout conditions that would occur prior to isolation of the faulted steam generator. Installation of the cavitating venturis prevents runout of the AFW pumps during these conditions.

The analyses of loss of normal feedwater and main feedwater line break for EPU conditions increase the required AFW flow from what is assumed in the current analysis. This is due to two changes, which are occurring at BVPS-1. First the higher core power level increases the heat which must be removed following these events. Second, the low-low level trip setpoint on the Model 54F steam generators is lower than that on the original Model 51 steam generator resulting in a delay in the reactor trip and a lower water inventory in the steam generator at the time of trip. The installation of the cavitating venturis in the BVPS-1 AFW system also contributes to a higher system head loss. These combined effects increase the pump performance requirements to the point where one motor-driven pump is no longer sufficient. Therefore, BVPS-1 now must credit two motor-driven AFW pumps to meet the assumptions for the design basis safety analyses. Crediting of two AFW pumps is consistent with the original licensing basis for BVPS-2 for main feedwater line breaks and still meets all single failure design requirements. Technical Specification 3.7.1.2 requires that all three AFW pumps be operable.

B.6 Question (Applicable to EPU)

The licensee's response, 5.c, Item 4 (as provided in Attachment E of the February 23, 2005, EPU supplement), indicates that the BVPS-1 licensing basis does not include plant cooldown as a consideration for the required volume in the primary plant demineralized water storage tank. Because this position appears to be inconsistent with the acceptance criteria that were applied to the BVPS-1 auxiliary feedwater system and reflected in a letter to Duquesne Light Company (then the licensee for BVPS-1) dated October 11, 1979, and it does not reflect the licensee's implementation of this criteria, additional explanation is required to confirm the nature of the proposed change.

Response:

The current Technical Specification 3.7.1.3 Bases state that sufficient water is available for cooldown of the Reactor Coolant System to less than 350 °F in the event of a total loss of off-site power. This describes a natural circulation cooldown scenario in which the maximum cooldown rate is limited to 25 °F/hour. This scenario would require inventory sufficient for at least 8 hours of decay heat plus all sensible heat loads down to 350 °F.

The NRC letter dated October 11, 1979 correctly reflects the system description in Section X.1.1.1 which states "The primary water supply of the AFWS is maintained in a 140,000 gallon seismic Category I, Primary Plant Demineralized Water Storage Tank (DWST).

The tank is reserved strictly for the AFWS pump usage. The reserved water inventory is sufficient to maintain the plant at hot standby condition for 8 hours following a reactor trip. Low water level in the DWST will alarm and annunciate in the main control room. The secondary water supply is the seismic Category I river water system with an additional backup from the fire protection system." The only change to this statement from the October 11, 1979 NRC letter is that FENOC has always stated that the BVPS-1 inventory is sufficient to maintain hot standby conditions for 9 hours. No other specific acceptance criteria or recommendations could be found in this letter relating to inventory requirements for cooldown scenarios.

Enclosure 2 of the October 11, 1979 NRC letter requested design basis information applicable to a list of events including plant cooldown. BVPS responded to the NRC request in a letter dated March 25, 1980. The BVPS response letter states that an analysis was performed to demonstrate that adequate tank sizing was provided to perform a normal cooldown. This is defined by the assumptions listed in Table 2-1 of the response letter which shows that the analysis was based on two hours at hot standby and reaching Residual Heat Removal System (RHRS) entry conditions (350 °F) in four hours with all RCPs operating. This scenario is quite different than that described in the current Technical Specification bases.

BVPS-1 is defined as a Category 3 plant per Branch Technical Position RSB 5-1 since the operating license was issued prior to January 1, 1979. Therefore, the specific AFW inventory requirements of this BTP do not apply to BVPS-1 (i.e. demonstration of sufficient inventory to cool the plant to RHRS entry conditions is not required). The BVPS-1 AFW system relies on the safety grade backup systems in the event that the inventory is not sufficient for any event beyond maintaining hot standby conditions for 9 hours.

Part C - Electrical Section 3.0 of Attachment C of February 23, 2005, EPU Supplement

C.1 Question (Applicable to EPU)

(Response a) There are load changes due to modifications performed as a result of EPU on the 125 Vdc system. Please provide the magnitude of load change and a detailed discussion on the changes in voltage calculations, short circuit calculations etc., and available margin.

Response:

As previously stated in FENOC letter L-05-078 dated May 26, 2005, Question H.8, 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 Valves (FWIVs) during the BVPS-1 refueling outage in the fall of 2004. The magnitude of these additional loads and their effect on voltage calculations, battery loading calculations, and short circuit calculations, including any impact on available margins, are summarized below.

Three fast closing 125 Vdc Feedwater Isolation Valves with a loading of 81.75 watts each were added, for a total of 245.25 watts additional loading on the 125 V DC system. The additional loads result in a calculated voltage of 109.46 volts at the valve terminals for the worst case, which provided nearly 10% margin above minimum required voltage of 100 volts. Because the total load increase on the 125 Vdc system is very small, the impact on the overall 125 Vdc bus voltage is negligible.

All three FWIVs were added on station battery BAT-3. BAT-3 was manufactured with 19 positive plates. The BVPS battery sizing analysis was performed using IEEE 485 –1983 guidelines of using an aging factor of 1.25, a design margin of 1.0, and a temperature correction factor of 1.19. Based on the battery loading requirement of 246.55 amps (includes 5% margin), the battery sizing analysis required 7.04 positive plates. By adding the margin listed above, the battery sizing analysis required 10.48 positive plates. The battery is designed for 19 positive plates; therefore, the existing battery is adequately sized for the added EPU loading.

There is no impact to the DC short circuit analysis due to the addition of the FWIVs at BVPS-1. The short circuit analysis was performed using only cable impedance and the battery open circuit voltage to calculate the available DC short circuit current. Therefore, any additional impedance from the valve loads or reduced battery voltage due to the valve loads has no effect on the analysis.

In conclusion, the existing battery is adequately sized for the added EPU loading and the 125 Vdc system is adequate for EPU conditions.

C.2 Question (Applicable to EPU)

(Response b) Please provide a detailed discussion on: 1) the load changes (e.g. brake horse power changes of loads) due to EPU and, 2) the basis (voltage at the load terminals and safety buses before and after EPU) for stating that adequate voltage is available at the load terminals and that no change in degraded voltage relay settings.

Response:

To confirm that each motor is adequately sized to support plant operation at EPU conditions, BHP for motors affected by EPU were evaluated. The evaluation concluded that the affected motors are sized adequately, and available starting and running voltages at the motor terminals is above minimum required voltage based on degraded voltage. The voltage on 4160 V and 480V busses during normal plant operation and during accident conditions have been analyzed at EPU conditions and have been shown to be above the present degraded grid voltage relay drop-out settings, including all tolerances. As such, no changes to degraded relay grid voltage relay settings are necessary. The results of the evaluation are tabulated in Tables C.2-1 for BVPS-1 and Table C.2-2 for BVPS-2.

The voltage drop calculations were performed using degraded relay voltage dropout setting of 92.4% of the busses. For emergency 4160-volt busses, a value of 3844 volts was used, and for 480-volt busses, a value of 444 volts was used to perform voltage drop analyses. For non-1E 4160-volt busses, a value of 4050 volts was used, and for 480-volt busses, a value of 444 volts was used to perform voltage drop analyses. It is noted that the Containment Air Recirculation (CAR) fans are not Emergency Diesel Generator (EDG) loads. With the loss of offsite power, the CAR fans are tripped and will not energize with the EDG load sequencer.

BVPS-1, Table C.2-1

Affected Pump Motor Load	Rated HP	Rated Full-load Amps	Pre-Uprate Load BHP	Uprate Load BHP	Load Current Before Uprate Amps	Load Current at Uprate, Amps	Bus Voltage, Volts	Running Voltage Prior to Uprate	Running Voltage at Uprate	Starting Voltage Prior to Uprate	Starting Voltage at Uprate
Condensate Pump	3000	355	3075	3170	399	411	4050				
CN-P-1A								4042	4042	4014	4014
CN-P-1B								4041	4041	4011	4011
Heater Drain Pump	1750	206	1650	1680	215	219	4050				
SD-P-1A								4045	4045	4033	4033
SD-P-1B								4044	4044	4031	4031
Reactor Coolant Pump	6000	731	5220	6335	721	875	4050				
RC-P-1A								4028	4031	3955	3955
RC-P-1B								4035	4037	3982	3982
RC-P-1C								4030	4032	3961	3961
Second. Component											
Cooling Pump	500	62	469	473	65	65	4050				
CC-P-3A								4043	4044	4037	4037
CC-P-3B								4044	4044	4036	4036
Steam Generator											
Feedwater Pump	4000	460	4010	3190	511	407	4050				
FW-P-1A1								4044	4043	4024	4024
FW-P-1A2								4044	4045	4023	4023
FW-P-1B1								4045	4046	4029	4029
FW-P-1B2								4044	4045	4025	4025
*Charging Pump	600	72	696.87 (DBA) 517 (LOOP)	695 (DBA) 584.9 (LOOP)	92.8 (DBA) 69 (LOOP)	92.2 (DBA) 78 (LOOP)	3844				
CH-P-1A								3834	3835	3825	3825
CH-P-1B								3826	3829	3810	3810
CH-P-1C								3836	3837	3828	3828
**CAR Fans	300	344	290	315	371	402	444				
VS-F-1A								424	422	357	357
VS-F-1B								429	428	379	379
VS-F-1C								420	418	340	340

BVPS-1, Table C.2-1 (cont.)

Affected Pump Motor Load	Rated HP	Rated Full-load Amps	Pre-Uprate Load BHP	Uprate Load BHP	Load Current Before Uprate Amps	Load Current at Uprate, Amps	Bus Voltage, Volts	Running Voltage Prior to Uprate	Running Voltage at Uprate	Starting Voltage Prior to Uprate	Starting Voltage at Uprate
*CRDM Shroud Fans	200	231	120	136	154	175	444				
VS-F-2A								431	431	363	363
VS-F-2B								437	436	397	397
VS-F-2C								432	428	346	346

NOTES:

* Motors on 1E bus

** Motors on 1E bus (not loaded on EDG)

Load currents are calculated at 90% of the rated motor voltage.

BVPS-2, Table C.2-2

Affected Pump Motor Load	Rated HP	Rated Full-load Amps	Pre-Uprate Load BHP	Uprate Load BHP	Load Current Before Uprate Amps	Load Current at Uprate, Amps	Bus Voltage, Volts	Running Voltage Prior to Uprate	Running Voltage at Uprate	Starting Voltage Prior to Uprate	Starting Voltage at Uprate
Condensate Pump	3500	415	3500	3150	462	415	4050				
2CNM-P21A								4039	4039	4019	4019
2CNM-P21B								4042	4042	4027	4027
2CNM-P21C								4040	4040	4022	4022
Heater Drain Pump	800	96	800	713	109	97	4050				
2HDH-P21A								4042	4042	4029	4029
2HDH-P21B								4044	4044	4034	4034
Separator Drain Pump	300	38.5	300	279	42	39	4050				
2HDH-P22A								4048	4048	4044	4044
2HDH-P22B								4047	4047	4042	4042
Reactor Coolant Pump	6000	731	5708	5768	788	797	4050				
2RCS*P21A								4036	4039	3992	3992
2RCS*P21B								4045	4045	4023	4023
2RCS*P21C								4035	4038	3985	3985
Second. Component Cooling Pump	600	80	530	529	78	78	4050				
2CCS-P21A								4040	4040	4024	4024
2CCS-P21B								4055	4045	4034	4034
Steam Generator Feedwater Pump	4000	493	3575	3190	466	415	4050				
2FWS-P21A1								4039	4040	4011	4011
2FWS-P21A2								4039	4041	4013	4013
2FWS-P21B1								4041	4042	4016	4016
2FWS-P21B2								4042	4043	4020	4020
*Charging Pumps	600	72	662 (DBA)	690 (DBA)	88 (DBA)	92 (DBA)	3844				
2CHS*P21A			517	584.9	69	78		3822	3823	3818	3818
2CHS*P21B			(LOOP)	(LOOP)	(LOOP)	(LOOP)		3819	3820	3813	3813
2CHS*P21C								3821	3822	3816	3816

BVPS-2, Table C.2-2 (Cont.)

Affected Pump Motor Load	Rated HP	Rated Full-load Amps	Pre-Uprate Load BHP	Uprate Load BHP	Load Current Before Uprate Amps	Load Current at Uprate, Amps	Bus Voltage, Volts	Running Voltage Prior to Uprate	Running Voltage at Uprate	Starting Voltage Prior to Uprate	Starting Voltage at Uprate
**CAR Fans	300	349	291	315	377	408	444				
2HVR-FN201A								428	424	389	389
2HVR-FN201B								428	426	380	380
2HVR-FN-201C								426	421	377	377
*CRDM Shroud Fans	75	92	## 75	75	89	102	444				
2HVR-FN202A1								427	426	387	384
2HVR-FN202B1								431	430	402	399
# 2HVR-FN202C1								428	428	389	389
# 2HVR-FN202A2								433	433	407	407
# 2HVR-FN202B2								431	431	401	401
# 2HVR-FN202C2								432	432	405	405

NOTES:

* Motors on 1E bus

** Motors on 1E bus (not loaded on EDG)

\# Motor has been replaced

\## Actual pre-uprate load for CRDM fans is 36 BHP, which was used in EDG analysis. The voltage drop analysis used the motor nameplate value (75 HP) for conservatism.

Load currents are calculated at 90% of the rated motor voltage.

C.3 Question (Applicable to EPU)

(Response c) It appears to be a mismatch between grid minimum (339.8 kV) and maximum (355.4 kV) and generator minimum (99.1% of rated voltage for BVPS-1 and 99.9% of rated voltage for BVPS-2) and grid maximum (101.4% for BVPS-1 and 102.6% for BVPS-2). Please explain. For example: Grid minimum voltage of 339.8 kV will result in 96.26% [(339.8/345 kV) x (21.5/22 kV) x 100 = 96.26%] of generator terminal voltage.

Response:

There is a mismatch in the allowable minimum generator voltage and the grid voltage if transformer losses, and the voltage drop due to the transformer losses, along with the losses due to current flowing from the main generator losses are ignored.

The voltage limits were calculated using Electrical Transient Analyzer Program (ETAP software), which is 10 CFR 50 Appendix B software and widely used in the nuclear industry. The minimum calculated generator voltage was obtained by setting ETAP parameters at minimum grid voltage and maximum possible loading on the busses. The calculations were performed by changing the main generator voltage until the minimum voltage at the 480 volt emergency busses are just above the degraded grid relay reset point. For both BVPS units, the degraded grid relays reset points are set at 95.3% for the 480 volt bus (which equates to 457.4 volts) and the ETAP program was set with maximum possible load on the non-Class 1E busses. The main generator voltage was lowered until the voltage at the Class 1E 480 volt substations was just above 457.4 volts. When the generator is paralleled with the grid, the software considers the grid as an infinite bus. Any change in generator voltage does not change the voltage on an infinite bus (grid) but it changes the VAR flow on the grid. An increase in generator voltage with reference to grid voltage will cause VAR flow towards the grid and vice versa. Therefore, even though there is a mismatch in grid voltage and generator voltage, the mismatches are expected and acceptable.

For each BVPS Main Generator, voltage limits at EPU levels are selected to properly operate for the normally expected deviations with respect to the grid voltage. This prevents the 4kV and 480V bus voltages from dropping below the degraded grid relays reset points. This also prevents the Main Generator from operating in an under-excitation condition, and prevents the Main Generator and the 4kV and 480V busses from exceeding maximum voltage limits. Therefore, the generator/grid voltage mismatches are expected and acceptable.

C.4 Question (Applicable to EPU)

(Response d) Please provide emergency diesel generator loading before and after EPU and its impact on the available extra capacity to be used as an AAC power source. Please provide a detailed discussion on the impact of EPU on station blackout (SBO) and design-basis accidents.

Response:

For both BVPS units, there are only two loads on the emergency diesel generators (EDGs) that change as a result of EPU, the charging pumps and the CRDM fans. (NOTE: The load changes for the CRDM fans are actually due to containment conversion, in support of EPU). The magnitude of the load increases on the EDGs and the impact on the available extra capacity as an AAC source for SBO, as well as the impact on design-basis accidents, were previously provided in FENOC letter L-05-078 dated May 26, 2005, RAI H.4. The pertinent information from the RAI H.4 response is summarized as follows.

BVPS 1

The Emergency Diesel Generator (EDG) loading analysis identifies the charging pump loading for Loss-of-Offsite-Power (LOOP), Safety Injection (SI), Design Basis Accident (DBA), and Station Blackout (SBO) conditions. The BVPS-1 charging pump rotating assemblies have already been replaced for the EPU. The existing pre-EPU maximum loading for the charging pump motor was identified as 696.87 BHP during SI and Containment Isolation Phase B (CIB) conditions. Although the motor would be operating beyond its service factor, this condition has been analyzed and found to be acceptable. To ensure that post EPU SI and DBA loading will remain bounded by the previous analyses, the charging pump discharge valves are verified to be in their correct throttled position each outage.

For the LOOP condition, the HHSI pump calculated BHP increased from 517 BHP to 584.9 BHP for EPU. The Control Rod Drive Mechanism (CRDM) fan loading also increased from 120 BHP to 136 BHP due to containment conversion, in support of EPU. The EDG loading analysis accounted for these load changes and concluded that the maximum coincident load is less than 2745 KW for all operating conditions (DBA, SI, LOOP), except for Station Blackout where the load is less than 2850 KW. Available margin, dependent on the particular operating scenario, varies between a minimum of 29 KW (for a DBA) and a maximum of 135 KW* (for a LOOP). The minimum margin of 29 KW for a DBA will last for one to two hours. After the Quench Spray Pump is shut down, the margin will be 176 KW. The total EDG loads for LOOP, SI and DBA do not exceed the UFSAR requirement of 2745 KW and the SBO loading does not exceed the EDG 2000-hour rating of 2850 KW.

A comparison of the BVPS-1 EDG loading before and after EPU is provided below:

EDG Margin For BVPS Unit 1				
	DBA (KW)	LOOP (KW)	SI (KW)	SBO (KW)
Pre EPU	28	203	109	123
Post EPU	29	135*	97	55

*NOTE: This value (135 KW for a LOOP) supercedes the previous value provided in our May 26, 2005 response (L-05-078) for RAI response H.4 which inadvertently identified the value as 109 KW for a LOOP.

BVPS-2

The BVPS-2 EDG loading analysis identifies the charging pump loading for LOOP, SI, DBA, and SBO conditions. The EPU maximum loading for the charging pump was identified as 695.1 BHP during SI and DBA conditions. The higher charging pump loading occurs at pump operation near run out conditions due to the drop in RCS pressure. In this condition, the motor will be operating at its service factor. For LOOP accident conditions, the calculated BHP is 584.9 BHP. The Control Rod Drive Mechanism (CRDM) fan loading also increased from 36 BHP to 75 BHP due to containment conversion in support of EPU. The EDG loading analysis accounted for these load changes and the maximum coincident load is less than

4535 KW for all operating conditions (LOOP, SI, DBA and SBO). Available margin, dependent on the particular operating scenario, varies between a minimum of 129 KW (for SBO) and a maximum of 1421 KW (for SI). The total EDG loads for LOOP, DBA, SI and SBO do not exceed the UFSAR design requirement of 4535 KW.

A comparison of the BVPS-2 EDG loading before and after EPU is provided below:

EDG Margin For BVPS Unit 2				
	DBA (KW)	LOOP (KW)	SI (KW)	SBO (KW)
Pre EPU	890	1336	1447	332
Post EPU	863	1187	1421	129

C.5 Question (Applicable to EPU)

(Response e) In response to "a" above, the licensee stated that DC load has increased. Please provide a detailed discussion on the capability to cope with an SBO during the initial 1-hour period prior to AAC capability becoming available due to changes on the DC system resulting from the EPU.

Response:

During a SBO, station batteries, inverters, and related distribution systems are available with capability to cope during the initial 1-hour period prior to AAC capability. The 125 Vdc system consists of safety and non-safety-related 125 Vdc busses 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 changes that would impact the design capability of the station batteries, inverters and related distribution systems and, therefore, the 125 Vdc system is unaffected by EPU. For BVPS-1, the only change to the 125 Vdc system loading has been the addition of the fast closing Feedwater Isolation Valves (FWIVs) during the BVPS-1 refueling outage in the fall of 2004. The engineering change for addition of these valves has been completed and confirmed that it does not impact the design capability of the 125 Vdc system as discussed in the response to Question C.1. It has been concluded that these systems will be available with sufficient capability to cope during the initial 1-hour period prior to AAC capability.

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 the revised loading was found to be within EDG capability (2850 KW). The BVPS-2 EDG loading analysis was updated to include EPU loading for SBO conditions and the revised loading was found to be within EDG capability (4535 KW). Therefore, the EDGs will remain capable of performing their function as the AAC power capability for EPU conditions.