FENOC

FirstEnergy Nuclear Operating Company

Peter P. Sena III
Site Vice President

724-682-5234
Fax: 724-643-8069

June 16, 2008
L-08-188

10 CFR 54

ATTN: Document Control Desk
U. S. Nuclear Regulatory Commission
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
Reply to Request for Additional Information for the Review of the Beaver Valley Power Station, Units 1 and 2, License Renewal Application (TAC Nos. MD6593 and MD6594) and License Renewal Application Amendment No. 13

Reference 1 provided the FirstEnergy Nuclear Operating Company (FENOC) License Renewal Application (LRA) for the Beaver Valley Power Station (BVPS). Reference 2 requested additional information from FENOC regarding the BVPS license renewal integrated plant assessment in Sections B.2.1, B.2.3, B.2.4, 3.5.2.1, 3.5.2.2, 3.5.2.3, and 4.6.2 of the BVPS LRA.

The Attachment provides the FENOC reply to the U.S. Nuclear Regulatory Commission request for additional information. The Enclosure provides Amendment No. 13 to the BVPS License Renewal Application.

There are no regulatory commitments contained in this letter. If there are any questions or if additional information is required, please contact Mr. Clifford I. Custer, Fleet License Renewal Project Manager, at 724-682-7139.

I declare under penalty of perjury that the foregoing is true and correct. Executed on June 16, 2008.

Sincerely,

Peter P. Sena III

A108
NRR

References:
1. FENOC Letter L-07-113, "License Renewal Application," August 27, 2007.
2. NRC Letter, "Request for Additional Information for the Review of the Beaver Valley Power Station, Units 1 and 2, License Renewal Application (TAC Nos. MD6593 and MD6594)," May 8, 2008.

Attachment:
Reply to Request for Additional Information Regarding Beaver Valley Power Station, Units 1 and 2, License Renewal Application, Sections B.2.1, B.2.3, B.2.4, 3.5.2.1, 3.5.2.2, 3.5.2.3, and 4.6.2

Enclosure:
Amendment No. 13 to the BVPS License Renewal Application

cc: Mr. K. L. Howard, NRC DLR Project Manager
Mr. S. J. Collins, NRC Region I Administrator

cc: w/o Attachment or Enclosure
Dr. S. S. Lee, NRC DLR Acting Director
Mr. D. L. Werkheiser, NRC Senior Resident Inspector
Ms. N. S. Morgan, NRC DORL Project Manager
Mr. D. J. Allard, PA BRP/DEP Director
Mr. L. E. Ryan, PA BRP/DEP

<u>**Section B.2.1, Appendix J**</u>

Question RAI B.2.1-1

In LRA Section 2.1, the applicant stated in the "Program Description" aging management program (AMP) element that BVPS uses option B, the performance-based approach to implement the containment leak rate tests. Since the relaxation of option B of the Integrated Leak Rate Test (ILRT) frequency is based on the risk impact assessment, the applicant is required to assess the risk impact incorporating the liner corrosion on the inaccessible side based on the 2006 findings for the period of extended operation. Please provide this assessment.

RESPONSE RAI B.2.1-1

The one-time relaxation of the Beaver Valley Power Station (BVPS) 10 CFR 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors," Option B, "Performance-Based Requirements," Integrated Leak Rate Test (ILRT) frequency allowed a five-year extension to the normal test frequency of once every 10 years, for a one-time 15-year test interval. The submittal (ML023080364), approved by the NRC (Safety Evaluation Report dated March 5, 2003, ML030640880), included the results of a risk assessment which included evaluation of the risk of an unidentified through-wall leak in the containment liner due to corrosion. These results showed that there was relatively little risk in extending the ILRT test frequency one time.

After the discovery of the BVPS Unit 1 containment liner corrosion in 2006, a satisfactory ILRT was completed prior to restarting the unit. With the successful performance of this ILRT, Unit 1 returned to the normal Option B ILRT frequency of once every 10 years. The risk assessment performed to evaluate the risk of extending the ILRT frequency no longer applied following the 2006 ILRT. The BVPS ILRT frequency is specified in the BVPS Containment Leakage Rate Testing Program and is in accordance with 10 CFR Part 50, Appendix J, Option B, Section III.A.

Given that a successful ILRT was performed after an extended frequency, FirstEnergy Nuclear Operating Company's (FENOC's) continued adherence to the Option B program provides reasonable assurance that the integrity of the containment liner will be adequately managed for the period of extended operation.

Question RAI B.2.1-2

Prior to initiating an ILRT test, a visual examination has to be conducted of accessible interior and exterior surfaces of the containment system. The purpose of the visual examination is to detect and repair, if necessary, structural degradation before an ILRT is performed. Since steel liner degradation may exist on the inaccessible side at BVPS, please explain how you addressed this issue in the ILRT pretest procedure.

RESPONSE RAI B.2.1-2

There is no practical means by which the inaccessible side of the containment liner can be examined. Corrosion of the liner plate from the concrete side is not considered an aging effect since there is no active mechanism for corrosion (See FENOC response to RAI B.2.3-1).

In accordance with 10 CFR 50, Appendix J, Option B, FENOC performs a general visual inspection of the accessible interior and exterior surfaces of the containment structures and components prior to each ILRT to uncover evidence of structural deterioration which may affect either the containment structural integrity or leak-tightness. Such evidence includes, but is not limited to, paint peeling off the liner, rust spots on the liner, welding deficiencies at liner attachments, liner plate bulges or disfigurement, and caulking deficiencies at the floor / wall intersection. The accessible portions of the containment dome liner and the cylindrical containment wall liner are included in the inspection.

Evidence of structural deterioration which may affect either the containment structural integrity or leak-tightness is entered into the FENOC Corrective Action Program.

Two additional requirements were incorporated into the containment inspection procedures as a result of the liner corrosion found in 2006:

1. When paint or coatings are to be removed for further inspection, the paint or coatings shall be visually examined by a qualified VT-3 inspector prior to removal.
2. If the visual examination detects surface flaws on the liner or suspect areas on the liner plate that could potentially impact the leak tightness or structural integrity of the liner, then surface or volumetric examinations shall be performed to characterize the condition (i.e., depth, size, shape, orientation).

The inspections are performed prior to initiating a containment ILRT, and during two other refueling outages prior to the next ILRT (provided the interval for the ILRT has been extended to 10 years).

In addition to the visual inspections, FENOC performs the containment ILRT, which verifies the leak-tight integrity of the containment and measures overall integrated containment leakage to assure compliance with BVPS technical specifications.

Together, the visual inspections and ILRT provide reasonable assurance that the containment liners at BVPS will continue to perform their intended functions for the period of extended operation.

Section B.2.3, IWE

Question RAI B.2.3-1

In LRA Section 2.3, the applicant stated in the "Operating Experience" AMP element that a temporary construction opening of Unit 1 containment in 2006 during the cycle 17 refueling outage revealed degradation from the inaccessible side of steel liner for which the applicant could not identify a root-cause from the observations in field or from the lab analysis. Since the steel liner is a key component in ensuring the essential leak-tight condition of the containment, please provide information related to the minimum required thickness of the liner. Include a discussion on the possibility and severity of the similar corrosion at other locations including Unit 2 containment, and to justify if the corrosion is active or not. If the corrosion is an aging effect, the GALL Report recommends further evaluation of plant-specific programs to manage this aging effect for inaccessible areas if corrosion is significant.

RESPONSE RAI B.2.3-1

Analyses and evaluations of the Unit 1 containment liner corrosion in 2006 were performed for FENOC by several vendors that specialize in these types of analyses and by the FirstEnergy Beta Laboratory.

The Shaw Group, Inc., evaluated the condition of the Unit 1 containment liner regarding the extent of the degradation and effects on intended function following the discovery of the containment liner corrosion in 2006. The evaluation included consideration of the impact of an additional 20 years of operation as a result of license renewal on the recurring Integrated Leak Rate Test loading.

In the report, design basis calculations originally developed for the BVPS Unit 1 containment liner were used to demonstrate that the degraded conditions found on the liner did not adversely affect its mechanical/structural function as a leak-tight membrane. The thickness of the remaining sound metal was determined to be adequate to maintain the design safety function of the liner. In addition, the capacity of the concrete containment structure to withstand Design Basis Accident pressure was not adversely affected.

Of the three areas of corrosion identified, two were replaced with new plate material. The third area showed minimal wall loss at the deepest pit, and was left in place for further monitoring. In addition to initial "baseline" ultrasonic thickness measurements in accordance with Table IWE-2500-1, examination category E-C, it was recommended that the third area of degradation be mapped on the inside of the containment liner for future ultrasonic testing (UT) examinations. It was recommended that this area be examined for the next three inspection periods. If no change in liner thickness was detected after three inspection periods, it was determined that the area would require no additional inspections. Further engineering evaluation was recommended if the thickness changed. FENOC has scheduled additional UT examinations as recommended by The Shaw Group, Inc., for the three inspection periods following the 2006 refueling outage when the degradation was discovered.

A material analysis was also performed on the corroded steel liner areas and sample pieces of concrete to aid in determining a cause of the corrosion. The following conclusions were drawn concerning the corrosion activities:

- The corrosion was general pitting corrosion (wastage) with no evidence of stress corrosion or microbiological attack. The metallographic work performed by Beta Labs found the pitting to be rounded in nature with no crack like projections. The examination of the corrosion product trapped in the deep pits identified no usual levels of elements that were not expected to be present. No preferential corrosion attack was observed on the sample piece with the weld or on the welds around the Nelson studs welded to the liner plate. Some crevice corrosion was observed in the cross section of the studs where the flash weld could trap contaminates.
- The corrosion occurred after welding and construction of the liner plate since the corrosion pitting was even across the weld, the heat affected zone (HAZ) and both edges of the weld where weld prep would have occurred. No preferential corrosion occurred at the weld or HAZ.
- The necessary elements for corrosion (oxygen and water) were present throughout the construction phase of Unit 1, from the fabrication and erection of the liner plate through the completion of concrete pours for the top of the containment structure. During this timeframe, water, in the form of the wetting methodology used during the concrete pour sequences and weather (rain and snow), could accumulate in areas between the liner plate and the concrete structure. Corrosion activities are likely to have initiated during this construction period.
- Access to these necessary elements for corrosion activity became significantly limited once the concrete structure was completed. Exposure to water sources all but ceased, and the concrete/steel interface was no longer exposed to the atmosphere for re-oxygenation.

- The corrosion process consumes oxygen, and, once it is depleted, corrosion can not be sustained at a high rate due to the limited supply of oxygen between the concrete and the liner plate following fabrication.
- No corrosive agents or corrosion catalysts, such as chlorides, could be identified on or in the steel liner plate. Additionally, no corrosion agents were found in the pitted areas of the liner plate or in the concrete materials tested in concentrations that would be of concern. However, it must be considered that such materials may have existed in local areas and were removed during the water hydrolazing process that was used to remove the exterior containment concrete.
- Approximately 1% of the observable liner plate (portion removed for the construction opening) contained corroded areas and a much smaller percentage of the rebar surface area had evidence of corrosion. So, it is reasonable to assume that the concrete did not contain corrosive agents, and that corrosion elements (water and oxygen) were not present in abundant amounts. This finding would support the general conclusion that no general corrosion is active in the area between the liner plate and the concrete.
- The corrosion is localized for reasons that can not be determined with certainty. However, small breaks in the mill scale surface or other surface imperfections can provide the initiation sites for pitting (oxygen cell corrosion) during the time of construction when oxygen and water were known to be present.
- The concrete did contain small void areas at the concrete/steel interface. These voids would most likely have filled with water during the construction phase. During the post-construction life of the liner, these locations could also serve as an accumulation point for any moisture that enters the concrete structure. However, the area of the containment liner where the concrete was found to have small voids at the steel/concrete interface had no corrosion activity.
- Foreign material has been identified by other power plants that removed the liner plate from the inside of containment leaving the concrete in place. The foreign debris was identifiable in these instances since the corrosion product was available for analysis. At BVPS, little or no corrosion product remained following the water hydrolazing, so no conclusions could be drawn regarding the source of the corrosion.

A vendor materials specialist was commissioned to perform a corrosion assessment of the corroded steel liner, and stated that the primary source of passivation of the steel used in fabrication of the containment liner, studs and rebar is the concrete itself. The passivity of the steel depends upon the quality of the concrete in contact with the steel and the intimate contact of the steel by the concrete. The vendor concluded that, where the containment steel liner, studs and rebar are in contact with the concrete cover, the containment steel liner at BVPS Unit 1 would be in a passivated state and not subject to oxygen concentration cell corrosion. The visual inspection of the removed cutout and rebar identified that the majority (over 99%) of the surfaces in contact with the concrete were passive to an oxygen concentration cell corrosion mechanism.

Based on the evaluations and analyses in the reports on this issue, corrosion of the liner plate or rebar materials from the concrete side of the liner plate is not considered an aging effect since there is no active mechanism for corrosion. To confirm the absence of aging effects, FENOC has scheduled UT examinations of the affected area of the liner as recommended by The Shaw Group, Inc., for the three inspection periods following the 2006 refueling outage when the degradation was discovered. Because there is no active mechanism for corrosion, the parameters monitored by the BVPS ASME XI, Subsection IWE Program for Unit 1 and Unit 2 provide reasonable assurance that aging of the containment liners will be managed such that they will continue to perform their intended function for the period of extended operation.

Question RAI B.2.3-2

In the LRA Section 2.3, the applicant stated in the "Operating Experience" AMP element that following the Unit 1 cycle 17 refueling outage test procedures for the evaluation of the Containment liner plates were modified at both units. Please identify which test procedures or part of the procedures have been modified because of this finding and how it compares with the previous procedures, as well as the procedures provided by ASME Section XI, Subsection IWE. Explain whether the modified test procedures can help to detect a similar containment liner degradation on the side in contact with concrete. If not, please explain how to ensure that the similar degradation, if any, will be detected.

RESPONSE RAI B.2.3-2

The BVPS containment interior and exterior inspection procedure at each unit was modified to address potential corrosion of the liner material using visual inspection techniques. These procedures satisfy the ASME XI, Subsection IWE, General Visual Examination requirements for examination of Class MC (Metal Containment) surfaces. The Unit 1 and Unit 2 procedures were modified to include the following requirements:

1. When paint or coatings are to be removed for further inspection, the paint or coatings shall be visually examined by a qualified VT-3 inspector prior to removal.
2. If the visual examination detects surface flaws on the liner or suspect areas on the liner plate that could potentially impact the leak tightness or structural integrity of the liner, then surface or volumetric examinations shall be performed to characterize the condition (i.e., depth, size, shape, orientation).

There is no practical means by which the inaccessible side of the containment liner can be examined. Corrosion of the liner plate from the concrete side is not considered an aging effect since there is no active mechanism for corrosion (See FENOC response to RAI B.2.3-1). The procedural examinations listed above would identify degradation of the liner occurring from the concrete side, should it occur, which may affect either the containment structural integrity or leak-tightness.

These additional examination requirements and the use of the FENOC Corrective Action Program provide reasonable assurance that potential corrosion on the concrete side of the containment liner plate will be identified and addressed.

Question RAI B.2.3-3

The GALL AMP XI.S1, ASME Section XI, Subsection IWE states that ASME Section XI paragraph IWE-1240 requires augmented examinations of containment surface areas that are subject to degradation. Under the BVPS inservice inspection (ISI) Program - IWE, explain historically what inspection findings, including the 2006's findings of the liner degradation on the side in contact with concrete, have led to the need for augmented inspections. Explain any augmented inspections currently being performed on the containment surfaces; and if so, please provide the containment locations that are within the scope of the augmented inspections and what type of inspections have been performed.

RESPONSE RAI B.2.3-3

BVPS Unit 1 and Unit 2 do not meet the criteria for ASME Code augmented examinations as defined in ASME XI, IWE-1240. There are currently no ASME Section XI, Subsection IWE augmented examinations being performed at BVPS Unit 1 or Unit 2 on examination surface areas defined in IWE-1240.

However, following the discovery of the corrosion on the concrete side of the liner plate in 2006, two of the three degraded areas were removed and replaced with new plate material. The third area was found acceptable from examination and laboratory analysis and was left in place. As part of the corrective actions from the discovery, this third area is monitored with additional examinations; FENOC has scheduled additional UT examinations as recommended by The Shaw Group, Inc., for the three inspection periods following the 2006 refueling outage when the degradation was discovered.

Section B.2.4, IWF

Question RAI B.2.4-1

In LRA Section B.2.4 IWF AMP, the applicant identified six exceptions to GALL AMP XI.S3 due to the use of 1989 ASME edition. These exceptions included use of specific ASME Section XI Code Case N-491 as alternate rules for examination. The BVPS chose to use ASME Code Case N-491. However, in the "Operating Experience" element, the applicant indicated that Table IWF-2500-1 of ASME Section XI, Subsection IWF, 1989 edition was used instead of Table 2500-1 of Code Case N-491. Please clarify this issue and provide what version of Code Case N-491 was used.

RESPONSE RAI B.2.4-1

Table -2500-1 of ASME Code Case N-491 should have been cited in the "Operating Experience" discussion of LRA Section B.2.4, "ASME Section XI, Subsection IWF Program," instead of ASME XI, IWF. The first paragraph of LRA Section B.2.4, "Operating Experience," is revised to reference Code Case N-491.

The version of ASME Code Case N-491 used for the BVPS ASME Section XI, Subsection IWF Program, was Revision 0, dated March 14, 1991. The date listed in LRA Appendix B, Section B.3, "Appendix B References," is incorrect. LRA Reference B.3-4 is revised to provide the correct date.

See the Enclosure to this letter for the revisions to the BVPS LRA.

Section 3.5.2.1

Question RAI 3.5.2.1-1

Item 15 of LRA Table 3.5.2-36 refers to GALL Item VII.G-8, for cable trays and conduits component, aluminum material, exposed to raw water environment, and loss of material aging effect. GALL Item VII.G-8 recommends the Fire Protection Program to manage the aging effect. However, the Structures Monitoring Program is credited in the LRA. Please justify why the applicant's Fire Protection Program is not credited, and how the applicant's Structures Monitoring Program includes all GALL suggested elements of the Fire Protection Program for this line item.

RESPONSE RAI 3.5.2.1-1

The Structures Monitoring Program is appropriate for monitoring the condition and function of cable trays and conduit, and is the better program to manage aging of cable trays and conduit exposed to raw water.

The Structures Monitoring Program was not compared to elements of the NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," Revision 1, Section XI.M26, "Fire Protection Program." FENOC compared aging evaluation results for cable trays and conduits in a raw water environment to NUREG-1801, Item VII.G-8, because the FENOC evaluation is consistent with the NUREG-1801 item for material, environment and aging effect, and VII.G-8 is the only available NUREG-1801 row that identifies aluminum components in an untreated water environment. These components are located below grade in the Intake bays or in safety-related valve pits, and may be exposed to accumulated (i.e., untreated) water.

The Fire Protection Program manages the aging effects on fire barrier penetration seals; fire barrier walls, ceilings and floors; fire wraps; and, fire rated doors that perform a current licensing basis fire barrier intended function. NUREG-1801, Section XI.M26, makes no mention of the support of cable trays and conduit, and the applicable components are not specifically associated with fire protection components or functions.

Cable trays and conduit provide structural support to electrical conductors, and NUREG-1801 Section XI.S6, "Structures Monitoring Program," specifically addresses structural components. Consequently, the Structures Monitoring Program is appropriate for monitoring the condition and function of such cable trays and conduit, and is the better program to manage aging of cable trays and conduit exposed to raw water.

Question RAI 3.5.2.1-2

Line items 36, 37, 38 and 248 of LRA Table 3.5.2-36 refer to GALL Item III.A6-11. GALL Item III.A6-11 recommends RG 1.127 program to manage the loss of material aging effect. However, the applicant's ASME Section XI, Subsection IWF Program is credited for these items. Please discuss how the elements of the RG 1.127 program are included in the applicant's ASME Section XI, Subsection IWF Program.

RESPONSE RAI 3.5.2.1-2

The BVPS ASME Section XI, Subsection IWF Program was not compared to elements of the GALL XI.S7, "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program." FENOC compared aging evaluation results for component and piping supports (ASME class 1, 2 and 3) and for anchor bolts and structural bolts (ASME class 1, 2, and 3 support bolting) in a raw water environment to NUREG-1801 III.A6-11 because the FENOC evaluation is consistent with the NUREG-1801 item for material, environment and aging effect, and III.A6-11 is the only available NUREG-1801 row that identifies steel structural components in an untreated water environment. These components are located underwater in the Intake bays, or in safety-related valve pits that may have accumulated (i.e., untreated) water.

BVPS does not have water-control structures as defined in Regulatory Guide 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants." Therefore, NUREG-1801, Chapter XI.S7, is not applicable to BVPS.

The NUREG-1801 XI.S7 program scope is focused on concrete and earthen materials, and does not specifically address loss of material of metallic components, ASME class 1, 2 and 3 supports, or bolting. The ASME Section XI, Subsection IWF Program, however, is specifically applicable to aging management for these support components. Therefore, the ASME Section XI, Subsection IWF program was assigned to manage their aging, and note E was assigned to LRA Table 3.5.2-36 rows 36, 37, 38, and 248 (note that row 38 does not align to NUREG-1801 III.A6-11).

Question RAI 3.5.2.1-3

Item 3 of LRA Table 3.5.2-17 refers to GALL Item VII.C3-7, for screen guides component, alloy steel material, exposed to raw water environment, and loss of material aging effect. GALL Item VII.C3-7 suggests the Open-Cycle Cooling Water System Program to manage the aging effect. However, the applicant's Structures Monitoring Program is credited for this item. Please justify why the applicant's Open-Cycle Cooling Water System Program is not credited, and how the applicant's Structures Monitoring Program covers all GALL suggested elements of the Open-Cycle Cooling Water System Program for this item.

RESPONSE RAI 3.5.2.1-3

The Open-Cycle Cooling Water (OCCW) System Program at BVPS satisfies Generic Letter (GL) 89-13, "Service Water System Problems Affecting Safety-Related Equipment," commitments for managing aging effects due to biofouling, corrosion, protective coating failures, and silting within system components. The focus of the program is the assurance of fluid flow thru critical cooling components; it does not focus on structural items, such as the subject Intake Structure traveling screen guides, which function to maintain the screens' alignment during operation, and which transfer loads to the concrete walls that support them.

The Structures Monitoring Program relies on periodic visual inspections to monitor the condition of structures and structural components so that intended functions are maintained through the period of extended operation. The Structures Monitoring Program, therefore, is a more appropriate inspection program to provide reasonable assurance that the screen guides will function as intended during the period of extended operation.

Question RAI 3.5.2.1-4

Some line items in LRA Table 3.5.2 refer to Note 518. Note 518 stated "The Structures Monitoring (B.2.39) Program is used to manage aging of these components. BVPS did not credit the RG 1.127 program, Inspection of Water-Control Structures Associated with Nuclear Power Plants, for managing aging. However, the Structures Monitoring (B.2.39) Program includes the elements of the RG 1.127 program necessary for BVPS structures." Please discuss how the elements of the RG 1.127 program are included in the applicant's Structures Monitoring Program.

RESPONSE RAI 3.5.2.1-4

NRC Regulatory Guide 1.127 is directed primarily at the maintenance of functionality for concrete and soil structures used to control cooling water, such as dams, canals and embankments. BVPS does not have water-control structures as defined in Regulatory Guide 1.127. Therefore, NUREG-1801, Chapter XI.S7, "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants," is not applicable to BVPS.

The common Intake Structure and the common Alternate Intake Structure are within the scope of the Structures Monitoring Program, but are not water-control structures as defined in Regulatory Guide 1.127. However, the elements of the Structures Monitoring Program that manage the aging of the intake structures are consistent with the applicable elements of Regulatory Guide 1.127.

The intake bays of these structures are normally submerged in water. Normally submerged structural items, such as steel supports, steel platforms, and concrete are inspected when the intake bays are drained for cleaning or maintenance. Regulatory Guide 1.127 specifies visual inspections as the primary means used to detect degradation of water-control structures. The Structures Monitoring Program specifies visual inspection of the intake structures and structural components.

For concrete, Regulatory Guide 1.127 specifies the parameters monitored to be cracking, movement, junctions, drains, water passages, seepage and leakage, construction joints, foundation, and abutments. The Structures Monitoring Program visual inspection includes structural components such as those described in the Regulatory Guide.

For intake and discharge structures, Regulatory Guide 1.127 specifies that the structure and all features should be examined for any condition that may impose operational constraints on the cooling facilities such as silt or debris at the water intake or discharge. The Structures Monitoring Program does not monitor silt or debris levels in the intake bays of the intake structures. However, this activity is performed by ongoing maintenance programs several times per year; the intake bays are monitored for buildup of silt/sludge, river debris, clams, and zebra mussels.

Regulatory Guide 1.127 specifies an inspection frequency of at least once every five years. The Structures Monitoring Program specifies an inspection frequency of at least once every five years.

Because the elements of the Structures Monitoring Program that manage the aging of the intake structures are consistent with the applicable elements of Regulatory Guide 1.127, there is reasonable assurance that aging effects for the subject systems, structures, and components will be adequately managed for the period of extended operation.

Section 3.5.2.2

Question RAI 3.5.2.2-1

In LRA Subsection 3.5.2.2, the applicant stated that the concrete specifications for BVPS concrete were designed in accordance with ACI 318 and constructed in accordance with ACI 301 using materials conforming to ACI and ASTM standards. The GALL Report suggests that concrete is constructed in accordance with the recommendations in ACI 201.2R for a quality concrete with low water-to-cement mix ratio (0.35-0.45), smaller aggregate, long curing period, adequate air entrainment (3-6%), and through consolidation. Please compare BVPS concrete with ACI 201.2R including water-to-cement ratio and air content.

RESPONSE RAI 3.5.2.2-1

The BVPS Unit 1 and Unit 2 Construction Phase concrete specifications that referenced ACI 301 and ACI 318 were initially issued in 1969 and 1973, respectively, and predated the initial issue of ACI 201.2R, "Guide to Durable Concrete," in 1977. Concrete quality for both units was stringently controlled by adherence to these specifications, which were approved by the NRC for plant construction (the Preliminary and Final Safety Analysis Reports referred to ACI 301 and 318). Concrete quality was established by mix design, and verified by constant control of materials, mixing, delivery, placement, curing and testing. Specifics, such as water-cement ratios, slumps, and entrained air content, were all controlled by the specifications.

There were six (6) structural mixes for Unit 1 (excluding grout, paste, floor topping, lean, and porous type mixes), and nine (9) structural mixes for Unit 2. Fly ash was used to replace 20% of the cement in the primary structural BVPS mix designs.

The mix proportion parameters, such as water-cement ratio, varied by mix design, but all mixes minimized the water-cement ratio, which was determined based upon achievement of mix design strength. Unit 1 structural concrete mixes and Unit 2 structural concrete mixes had water-cement ratios that varied between 0.40 and 0.55, which were appropriate for the strength, workability and durability desired for different applications (e.g., interior or exterior; foundations, walls or floors). ACI 201.2R-77, Section 1.4.2, recommends 0.45 to 0.50.

The use of "smaller" aggregate suggested by ACI 201.2R-77 relates to freeze-thaw damage potential. However, ACI 201.2R-77 leaves the final determination of aggregate selection (section 1.4.4.2) to the mix designer, since no explicit size criteria were established by ACI. Both BVPS units used a largest aggregate size meeting ASTM C33 No. 467 (1.5 in.) for the primary reactor containment exterior concrete mix, and No. 57 for the remainder of the general structural mixes. These aggregate sizes were selected during mix design by the project Architect/Engineer, Stone & Webster Corp, which had a lengthy experience record with major construction projects.

The BVPS mix designs addressed freeze-thaw damage potential by using entrained air (3% to 8%) and aggregate soundness testing for structures subject to freezing in the subgrade freeze zone and in water-tight structures. ACI 201.2R-77, Table 1.4.3, specifies an entrained air content range of 3% to 7.5% for various size aggregates used in concrete exposed to moderate to severe environments, respectively.

BVPS concrete curing required the application of curing compound, except where continuous wetting or standing water was used (massive concrete). Forms were kept in place until minimum concrete strengths were achieved depending upon the concrete's location in a structure (wall, beam, floor), as determined by concrete cylinder compression testing. ACI 201.2R-77, Section 1.4.5, recommends a minimum concrete strength of 500 psi before form removal, which is the same minimum specified at BVPS.

BVPS concrete placement specifications limited the permitted distance of lateral movement, drop distance, layer depth, and rate of placement. Thorough consolidation using vibrators was required, but minimized to avoid aggregate-paste segregation. ACI 201.2R-77, Section 1.4.6, recommends good consolidation and warns against overworking and excessive finishing of the concrete (slabs).

Although not designed to the NUREG-1801 recommended guidelines of ACI 201.2R-77, BVPS concrete mix design and concrete construction were carefully controlled, and are considered to have produced concrete of high quality and durability.

Question RAI 3.5.2.2-2

In LRA Section 3.5.2.2.1.1 and Item 3.5.1-01 of LRA Table 3.5.1, the applicant concluded that aging of concrete areas due to corrosion of embedded steel is not applicable to containment structures. However, in LRA Appendix B.2.5, "ASME Section XI, Subsection IWL", the following statement is made: "Previous BVPS Containment Building inspections have identified minor issues such as mildew and rust stains, spalling, surface cracks, and loose foreign materials." Please clarify if corrosion of embedded steel is the cause for rust stains and spalling and surface cracks. If yes, justify your conclusion in the LRA that the aging effect is not applicable, and related items in LRA Table 3.5.1 and Table 3.5.2.

RESPONSE RAI 3.5.2.2-2

The embedded steel items that caused the subject rust stains and small spalls were not load-carrying elements of the wall. Rather, they comprise construction accessories, such as wire tie attachment devices, or form ties that were used to hold forms in-place during construction and left in-place after the wall concrete was poured. These items are close to the exterior surface of the concrete cover layer (the outermost 3 inches that is not included in the wall's design thickness). They could not always be removed when the formwork was removed, and were instead covered by grout. Since they are near the concrete's surface, some of the items rust over time. and the grout over top of them pops off. This wire and form tie corrosion results in staining and small spalls.

Grout was also used to patch surface irregularities remaining after formwork removal, and these grout patches also occasionally spall off over time The spall is confined to the cover concrete.

A layer of shrinkage and temperature steel does exist under the cover concrete, which serves to limit surface cracking during initial concrete curing and subsequent temperature changes. On a few occasions, this small diameter (½ in.) steel has been exposed due to cover concrete spalling, which has also resulted in staining. The spalled areas were repaired in such cases.

The main reinforcing steel has not been found to be the source of rust stains or spalling on the reactor containment.

Question RAI 3.5.2.2-3

In LRA Section 3.5.2.2.1.1, the applicant concluded that the aging of concrete areas due to aggressive chemical attack is not applicable to concrete components below grade since BVPS groundwater chemistry is non-aggressive. The staff noted that the applicant has included groundwater monitoring under the Structures Monitoring Program. But there is no reference to any program to monitor BVPS above grade chemical conditions such as chemistry in air and rain due to the fact of surrounding industrial plants. If such inspections have been conducted, please specify the inspection frequency and chemical elements examined.

RESPONSE RAI 3.5.2.2-3

No program is needed to monitor air or rainwater chemistry. Groundwater chemistry is monitored to provide assurance that inaccessible (below-grade) concrete is not exposed to potentially adverse environments that might result in aging that would not be detected by visual inspections. Exterior, above grade surfaces of the concrete that would be exposed to ambient air environment are inspected for evidence of aging, which is consistent with NUREG-1801, item III.A1-6.

Question RAI 3.5.2.2-4

In LRA section 3.5.2.2.1.7, the applicant suggests that cracking due to SCC is not an applicable aging effect for the stainless steel penetration sleeves and bellows. However, SCC of the dissimilar metal welds is not discussed. Please (1) confirm whether cracking due to SCC is an applicable aging effect for dissimilar metal welds or not, (2) provide the history of the highest temperature that stainless steel penetration sleeves, penetration bellows, and dissimilar metal welds have been experienced, and (3) demonstrate what chemical elements that would support SCC have been monitored/inspected to ensure a none aggressive chemical environment.

RESPONSE RAI 3.5.2.2-4

1. "Cracking" is not an aging effect requiring management for dissimilar metal welds associated with the containment penetration bellows that are addressed in LRA Section 3.5.2.2.1.7, because the environment does not support cracking.

   FENOC used Electric Power Research Institute (EPRI) License Renewal documents 1010639, "Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools" (Mechanical Tools), Revision 4, and 1002950, "Aging Effects for Structures and Structural Components (Structural Tools)," Revision 1, as the primary aging effect references. FENOC considered stress corrosion cracking (SCC) to be an applicable aging effect for stainless steel, whether the material is used as a weld material or is the base material of a component, wherever applicable criteria are present. The stress required to support SCC may be either residual (e.g., due to fabrication, field installation, or welding), or may be due to operating conditions. Residual stresses are assumed to exist at levels that support SCC. EPRI Mechanical Tools identifies a threshold temperature of 140°F, below which SCC is not considered an aging effect requiring management. The subject penetration bellows that are discussed in LRA Section 3.5.2.2.1.7 are associated with the Unit 1 Recirculation Spray River Water outlet piping. These components are normally isolated, and so remain at ambient temperature, and do not exceed the threshold temperature for SCC. The EPRI Mechanical Tools notes that significant chloride contamination may support SCC even at low temperatures, but concludes that industry operating experience data does not indicate that SCC of stainless steel is a significant aging effect in raw water environments. BVPS operating experience reviews did not identify cracking below the EPRI Mechanical Tools threshold temperature as an aging effect requiring management.

2. The subject penetration bellows that are discussed in LRA Section 3.5.2.2.1.7 correspond to the Unit 1 Recirculation Spray River Water outlet piping. These components are normally at ambient temperature, and do not exceed 140°F (the threshold temperature for SCC). Operation with containment ambient air temperature exceeding 108°F is prohibited by Technical Specifications, and operation with Ohio River water temperature exceeding 90°F is prohibited by Technical Specifications. These limitations provide assurance that the penetration bellows associated with the River Water System supply to the Unit 1 Recirculation Spray heat exchangers have remained well below 140°F.

3. No specific contaminant levels are monitored for these components, since the threshold temperature for SCC is not exceeded. The EPRI Mechanical Tools notes that significant chloride contamination may support SCC even at low temperatures, but concludes that industry operating experience data does not indicate that SCC of stainless steel is a significant aging effect in raw water environments. BVPS operating experience reviews did not identify cracking below the EPRI Mechanical Tools threshold temperature as an aging effect requiring management. The external surfaces of the bellows are exposed to indoor air for which significant chemical contamination is not a normal condition.

Note that penetration bellows components are also addressed as expansion joints in LRA Table 3.3.2-28, lines 20-22. They are addressed separately as structural components in LRA Table 3.5.2-22, line 23, LRA Table 3.5.1-10, and LRA Section 3.5.2.2.1.7 as penetration bellows, because, while cracking is not identified as an aging effect requiring management, the 10 CFR Part 50, Appendix J and ASME

Section XI, Subsection IWE Programs are credited in LRA Plant-specific Note 501 as structural programs that will confirm the absence of significant aging effects.

Section 3.5.2.3

Question RAI 3.5.2.3-1

For item 1 of LRA Table 3.5.2-20,the applicant indicates that no aging effect requires management and therefore no AMP is applied for pile component type, carbon steel material, and below grade environment. Notes G and 512 are used for this line item. Note 512 states "Pipe piles driven in soils have been shown to be unaffected by corrosion." However, Note 526 states "Pipe piles driven into disturbed soils have been shown to experience only minor to moderate corrosion." Please justify why corrosion is not an aging effect for carbon steel material in below grade environment. If the pipe piles are vulnerable to corrosion, please explain how to monitor/inspect the factors of soil aggressiveness that would support pipe pile corrosion.

RESPONSE RAI 3.5.2.3-1

The basis for the FENOC conclusion that corrosion of pipe pile is not an aging effect requiring management is provided in the EPRI 1002950, "Aging Effects for Structures and Structural Components (Structural Tools)," Revision 1, Section 5.3.1.5:

> *"As part of an industry study, M. Romanoff examined corrosion data from 43 piling installations and on that basis drew some general conclusions regarding the corrosion of driven steel piles. The examined test installations had pile depths of up to 136 feet and time of exposure varying from 7 to 50 years in a wide variety of soil conditions. The results indicate that the type and amount of corrosion observed on steel pilings driven into undisturbed natural soil, regardless of the soil characteristics and properties, is not sufficient to significantly affect the strength of pilings as load bearing structures. The data also indicate that undisturbed natural soils are so deficient in oxygen at levels a few feet below the surface, or below the water table, that steel piles are not appreciably affected by corrosion. Because pipe piles driven in undisturbed soils have been shown to be unaffected by corrosion and those driven in disturbed soil have experienced only minor to moderate corrosion, loss of material due to corrosion is not an applicable aging effect for pipe piles for the period of extended operation. Plain, reinforced concrete piles or caissons in earth are generally considered permanent and are inherently durable unless the soil contains acids."*

Question RAI 3.5.2.3-2

For Items 1 and 15 of LRA Table 3.5.2-25,the applicant indicates that no aging effect requires management and therefore no AMP is applied for pump casement component type, carbon steel material, and below grade environment However, carbon steel is susceptible to corrosion in soil. Please justify why corrosion is not an aging effect for carbon steel material in below grade environment for pump casement component.

RESPONSE RAI 3.5.2.3-2

The components are vertical casements made from pipe that are installed in soil between structures. They include carbon steel pump casements (both units) and low alloy steel valve reach rod casements (Unit 1 only). The casements are above the groundwater table and are similar to pipe piles. The soil is fill. Pipe piles driven into disturbed soils have been shown to experience only minor to moderate corrosion. "Loss of material" due to corrosion is not an applicable aging effect for pipe piles (see also the FENOC response to RAI 3.5.2.3-1). Due to the similarity of the components to pipe piles, loss of material due to corrosion is not considered an applicable aging effect for pump or valve reach rod casements.

Question RAI 3.5.2.3-3

Items 4, 5, 6, 21, 22, and 23 of LRA Table 3.5.2-14 and Items 11, 12, 32, 38, 39, 77, 78, 95 and 97 of LRA Table 3.5.2-22 refer to GALL Item III.A5-13 and Notes I. GALL Item III.A5-13 is associated with (1) cracking due to SCC and (2) loss of material due to pitting and crevice corrosion for fuel pool liners. The staff notices that loss of material due to pitting and crevice corrosion is an applicable aging effect at BVPS. However, Note I suggests that the aging effect is not applicable. Please clarify why Note I is used for these line items.

RESPONSE RAI 3.5.2.3-3

The components associated with LRA Table 3.5.2-14 and 3.5.2-22 that are compared to NUREG-1801, item III.A5-13 are associated with the treated water environment of the spent fuel pools and refueling cavities. The FENOC aging evaluation for stainless steel in this environment confirmed the potential for "loss of material" due to pitting and crevice corrosion. However, the temperature of the spent fuel pools and refueling cavities does not exceed the threshold temperature for "cracking" (140°F). Therefore, the FENOC aging evaluation did not identify cracking due to SCC to be an aging effect requiring management for these components. NUREG-1801, item III.A5-13 specifically addresses the fuel pool liner, and was therefore judged to be the most appropriate

NUREG-1801 row for aging results comparison. However, III.A5-13 identifies both "cracking" due to SCC and "loss of material" due to pitting and crevice corrosion. Since FENOC did not identify cracking as an applicable aging effect for these components, LRA Plant-specific Note I was assigned to identify that the "Aging effect in NUREG-1801 for this component, material and environment combination is not applicable."

Question RAI 3.5.2.3-4

Items 221 and 222 of LRA Table 3.5.2-36 refer to Notes J and 527 for elastomer material and below grade environment,. For these two line items, no aging effect is identified and no AMP is applied by the applicant. Note J states "Neither the component nor the material and environment combination is evaluated in NUREG-1801", and Note 527 states "These below-grade elastomer components are sheltered from air, elevated temperature, and ultraviolet and ionizing radiation. They do not have aging effects requiring management." Please provide the technical basis of not having aging effects requiring management for elastomer material in below grade environment.

RESPONSE RAI 3.5.2.3-4

EPRI 1002950, "Aging Effects for Structures and Structural Components (Structural Tools)," Revision 1, was used to identify potential aging effects of the "Waterproofing membrane" and "Waterstop components". The potential aging effects associated with these materials as listed in the EPRI Structural Tools are "cracking" and "change in material properties". These aging effects may be caused by thermal exposure or by exposure to ionizing radiation. Additionally, for rubber, these effects may also be caused by exposure to ultraviolet radiation and ozone.

Cracking and change in material properties due to thermal exposure are not aging effects requiring management for elastomers below grade since the elastomers are sheltered by either concrete or structural backfill, and, therefore, are not exposed to temperatures greater than 95°F. Below grade waterstops are installed between wall and foundation mat junctions, waterproofing membranes are installed below grade to exterior horizontal and vertical surfaces of structures, and below grade piping expansion bellows (associated with Unit 1) are used to accommodate differential movement between the Reactor Containment Building and piping. Temperatures at installed locations for these elastomers are mild and are below the threshold where elastomer degradation can occur. Components below grade are not exposed to ionizing radiation above the threshold (1E+6 rads) for aging effects to be applicable. Components below grade are also shielded from exposure to ultraviolet radiation and ozone that could cause degradation of rubber. Therefore, there are no aging effects requiring management for these elastomer structural components in a below grade environment.

Section 4.6, Containment Liner TLAA

Question RAI 4.6.2-1

In LRA Section 4.6.2, "Containment Liner Corrosion Allowance," the applicant specified the corrosion allowance of the liner floor plate and the projected penetration due to corrosion of the inserted channel to the end of the period of extended operation. The staff reviewed the related on-site basis documents and found that a different thickness for corrosion allowance was calculated in one of the documents. Please explain the discrepancy of the corrosion allowance for the liner floor plate.

RESPONSE RAI 4.6.2-1

The corrosion allowance of 88 mils noted by the staff was based on corrosion rate information published by the General Electric Corporation. The basis document reviewed by the staff was a report prepared in March 1991; this report and earlier reports used the 88 mils corrosion allowance in the context that there is sufficient margin in the containment liner thickness to easily accommodate a corrosion of 88 mils.

The containment liner floor plate corrosion allowance of 125 mils provided in LRA Section 4.6.2 is based on the following:

1. Liner floor plate fabrication wall thickness of 0.25 inches (250 mils), and
2. Liner floor plate minimum wall thickness of 0.125 inches (125 mils) established by design analysis calculations.

Therefore, the corrosion allowance is calculated at 125 mils (250 mils minus 125 mils).

ENCLOSURE

Beaver Valley Power Station (BVPS), Unit Nos. 1 and 2

Letter L-08-188

Amendment No. 13 to the BVPS License Renewal Application

Sections Affected

Section B.2.4

Section B.3

The Enclosure identifies the correction by Affected License Renewal Application (LRA) Section, LRA Page No., and Affected Paragraph and Sentence. The count for the affected paragraph, sentence, bullet, etc. starts at the beginning of the affected section or at the top of the affected page, as applicable. Below each section the reason for the change is identified, and the sentence affected is printed in *italics* with deleted text *~~lined-out~~* and added text *underlined*.

Affected LRA Section	LRA Page No.	Affected Paragraph and Sentence
Section B.2.4	**Page B.2-11**	**2nd Paragraph (on page)**

LRA Section B.2.4, "ASME Section IX, Subsection IWF," "Operating Experience" subsection, incorrectly cited ASME XI, IWF, instead of ASME Code Case N-491. LRA Section B.2.4, page B.2-11, 1st paragraph under the heading "Operating Experience," is revised to read:

The VT-3 visual examination for supports is specified in Table ~~IWF~~ -2500-1 of ASME Code Case N-491. The complete inspection scope is repeated every 10-year inspection interval. Identification of unacceptable conditions triggers an expansion of the inspection scope in accordance with ~~IWF~~-2430 of ASME Code Case N-491, and reexamination of the supports requiring corrective actions during the next inspection period in accordance with ~~IWF~~ -2420(b) of ASME Code Case N-491.

Section B.3	**Page B.3-1**	**Reference B.3-4**

An incorrect date was listed for reference B.3-4 in LRA Section B.3, "Appendix B References." LRA Section B.3, page B.3-1, reference B.3-4, is revised to read:

ASME Code Case N-491, Alternate Rules for Examination of Class 1, 2, 3, and MC Component Supports of Light-Water Cooled Power Plants, March 14, 1991 ~~28, 2000~~.