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May 6, 2002

U.S. Nuclear Regulatory Commission
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Washington, DC 20555

Peach Bottom Atomic Power Station, Units 2 and 3
Facility Operating License Nos. DPR-44 and DPR-56
NRC Docket Nos. 50-277 and 50-278

Subject: Response to Request for Additional Information Related to Aging Management of Reactor Coolant System, Aging Management of Engineered Safety Feature Systems, Aging Management of Auxiliary Systems, and Aging Management of Steam and Power Conversion Systems

Reference: Letter from R. K. Anand (USNRC) to M. P. Gallagher (Exelon), dated February 6, 2002

Dear Sir/Madam:

Exelon Generation Company, LLC (Exelon) hereby submits the enclosed responses to the request for additional information transmitted in the reference letter. For your convenience, attachment 1 restates the questions from the reference letter and provides our responses.

If you have any questions or require additional information, please do not hesitate to call.

I declare under penalty of perjury that the foregoing is true and correct.

Respectfully,

Executed on 05-07-02

Michael P. Gallagher
Director, Licensing & Regulatory Affairs
Mid-Atlantic Regional Operating Group

Enclosures: Attachment 1

cc: H. J. Miller, Administrator, Region I, USNRC
A. C. McMurtray, USNRC Senior Resident Inspector, PBAPS

A087

ATTACHMENT 1

Exelon Generation Company, LLC (Exelon)
License Renewal Application (LRA)
Peach Bottom Atomic Power Station (PBAPS), Units 2 and 3

Request for Additional Information

3.1 Aging Management of Reactor Coolant System

RAI 3.1-1

This is a global RAI applicable to all systems.

The application does not identify the aging effects of cracking due to stress corrosion cracking (SCC), cyclic loading, wear, loss of pre-load, and loss of material for closure bolting for valves and pumps in any system. Bolting that is heat treated to a high hardness condition and exposed to a humid environment within containment could be susceptible to SCC. NUREG-1399, "Resolution of Generic Safety Issue 29: Bolting, Degradation or Failure in Nuclear Power Plants," indicates that the bolting material with yield strength greater than 150 ksi is susceptible to SCC. For high strength bolting, the effects of cyclic loading are generally seen in conjunction with SCC in causing crack initiation and growth. Vibration, cyclic loading, gasket creep and stress relaxation could cause loss of preload. Carbon steel bolting exposed to a humid environment within containment could be susceptible to loss of material.

The applicant should take into account the above information and review industry and plant experience to assess whether these aging effects are applicable for closure bolting. If such aging effects are applicable, the applicant should submit an aging management program to manage these aging effects in the closure bolting.

Response:

NEI 95-10 Revision 3, Industry Guideline for Implementing the Requirements of 10 CFR Part 54 – the License Renewal Rule, which is endorsed by NRC Regulatory Guide 1.188, does not consider bolting as a component. Based on this guideline, PBAPS LRA did not include it as a line item under component groups, although an AMR was performed for these piece parts. The environment that bolting would see would be external environments. External environments could be sheltered, outdoor, buried or submerged (raw water environment). These environments are described in PBAPS LRA section 3.0.

Closure bolting located in outdoor, buried, and submerged environments is unprotected and general corrosion, pitting and crevice corrosion are applicable loss of material aging mechanisms that cause loss of material aging effects requiring management. The Outdoor, Buried and Submerged Component Inspection Activities as described in Appendix B.2.5 manage these aging effects.

High strength bolting as is used for RPV head is included in Table 3.1-1 with an aging effect of cracking and is managed by the ISI program as described in Appendix B.1.8.

For other bolting, based on our plant operating experience, we have not considered any aging effects that require management. The following provides the rationale:

Loss of preload: Bolting pre-load is a design condition. Peach Bottom and industry operating experience has shown that proper closure bolting pre-load is effective in preventing mechanical joint leakage. A loss of pre-load would be detected by joint leakage before there is a catastrophic failure. Most loss of pre-load events are attributed to human error. According to the conclusion stated in the June 5, 1998, NRC letter from C.I.Grimes to D.Walters of NEI, in the subject matter of LR Issue No. 98-0013, "Degradation Induced Human Activities", degradation events induced by human activities need not be considered as a separate aging effect and should be excluded from an aging management review.

Wear and cyclic loading: Both are caused by vibration and prying loads aging mechanisms. Both of these are event related degradation mechanisms, and based on the NRC letter indicated above in the loss of pre-load paragraph, need not be considered as a separate aging effect and should be excluded from an aging management review.

Cracking due to stress corrosion cracking: SCC occurs through the combined actions of stress (either applied or residual), a corrosive environment, and a susceptible material. All three conditions must be present simultaneously to produce SCC. SCC is characterized by the base metal not being attacked over most of its surface while fine cracks have propagated through the microstructure. The threshold values for stress and corrosion are difficult to determine. Major suspected causes of SCC in fasteners are the use of lubricants containing sulfur compounds and the use of sealants containing fluorides or halides. Bolting materials susceptible to SCC are stainless steel and high-strength low alloy steel.

PBAPS implemented changes as a result of NRC generic correspondence on bolt cracking. PBAPS has a materials control program in place, which requires an evaluation of all chemicals and consumables to minimize the potential for damage to plant equipment. These administrative controls prevent the introduction of lubricants or sealants that may damage closure bolting. PBAPS does not have a history of closure bolting cracking. The vast majority of bolting failures due to SCCs have occurred at PWRs. Boric acid environment is the primary contributor to these SCC failures. Since PBAPS is a BWR, and does not have a boric acid environment, bolting does not experience conditions conducive to stress corrosion crack initiation and propagation. Therefore, cracking due to SCC is not considered an applicable aging effect for cracking of closure bolting.

Loss of material: For the plant sheltered environment, the presence of a continuous moisture source will typically not be in direct contact with threaded fasteners. In addition, during plant operation the drywell is inerted with nitrogen which reduces the oxygen concentration to less than 4% to render the atmosphere non-flammable. Lack of oxygen in the drywell has the added benefit of minimizing the potential for corrosion degradation. In general, moisture on the external surfaces of threaded fasteners could be caused by high humidity and resulting condensation or by system leakage. Plant sheltered environmental conditions during normal operations vary with the humidity ranging from 10% to 90%. To guard against condensation, anti-sweat insulation was specified for all piping and components where the process operating temperature is between 30-60°F or is below ambient. During installation, closure bolting is coated with grease to aid in obtaining proper pre-load. System leakage, when present, is repaired in a timely manner as part of the plant inspections, testing, and corrective actions activities and is not considered to be a long-term moisture source. PBAPS does not have a history of closure bolting loss of material when the bolting is located in a sheltered environment. Since the relevant conditions that contribute to the onset of general corrosion are being controlled, general corrosion is not considered an aging mechanism for closure bolting located in the plant sheltered environment.

RAI 3.1-2

(1) In Table 3.1-1 of the LRA, the applicant has identified cumulative fatigue damage as an aging effect for "other nozzles." According to Table 4.3.1-1 of the LRA, "other nozzles" appears to include RPV recirculation inlet and outlet nozzles. Verify that "other nozzles" includes the RPV recirculation inlet and outlet nozzles. Provide justification for not identifying cumulative fatigue damage as an aging effect for the remaining RPV nozzles (e.g., core spray nozzle).

(2) In Table 3.1-1 of the LRA, the applicant does not identify cumulative fatigue damage as an aging effect for nozzle safe-ends. However, BWRVIP-74 states that fatigue usage factors for safe-ends follow the same pattern as nozzles. Table 4.3.1-1 of the LRA includes RPV core spray nozzle safe-end as a fatigue monitoring program location. Provide technical justification for not including cumulative fatigue damage of safe-ends as an aging effect in Table 3.1-1.

(3) Table 3-1 of BWRVIP-74, "BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines," identifies cumulative fatigue as an aging effect for vessel flanges and stabilizer brackets. But Table 3.1-1 of the LRA does not identify cumulative fatigue damage as an aging effect for these two components. Provide the technical basis for excluding cumulative fatigue damage as an aging effect for these two components.

Response:

(1) Table 4.3.1-1 is a listing of the fatigue monitoring program locations. This table does not list all RPV nozzles and safe ends for which a fatigue analysis is a TLAA and for which cumulative fatigue damage is an aging effect, but only those locations expected to be used by the fatigue monitoring program.

All locations with a design-basis predicted 40-year CUF of 0.4 or greater are included, plus the highest usage factor in an analysis segment if less than 0.4, plus locations which field or industry experience suggest, including some in B31.1 piping, plus ECCS locations important to postulated accident scenarios. Tracking the fatigue usage factor for these locations will ensure that fatigue effects at all other locations with lower predicted usage factors will remain within acceptable limits.

Both "other nozzles" and safe ends are in fact included in the evaluation of RPV fatigue, as described in LRA Section 4.3.1. Therefore "other nozzles" in Table 3.1-1 is both correct and inclusive.

(2) Table 3.1-1 should have stated that safe ends are included in the evaluation of RPV fatigue, as indicated in the response to (1), above.

(3) Stabilizer brackets are not included in the list of 17 components in Table 3-1 of BWRVIP-74, "BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines". However, BWRVIP-74, section 3.2.2.6 identifies stabilizer brackets under vessel external attachments as having a potential for a significant fatigue usage. Our review of the original RPV vendor calculations indicates that the CUF for the Peach Bottom Units 2 & 3 stabilizer brackets was 0.17 for a 40-year life, which is significantly under 1.0 and therefore is not an issue for Peach Bottom license renewal.

The BWRVIP-74 table 3-1 does identify cumulative fatigue damage as an aging effect for the vessel flanges. However, BWRVIP-74, in section 3.2 on fatigue, under subsection 3.2.2, vessel flange is not identified as one of the locations of significance. Moreover, in the fatigue mechanism discussion in section 3.2.1 of the BWRVIP-74, concluding paragraph states, "The variation in calculated value for the vessel shell and the vessel flange strongly suggests that the assumptions used in these analyses vary widely. By using consistent and realistic assumptions, low cumulative usage factors will most likely result [23]." Reference 23 is the "BWR RPV License Renewal Industry Report, Revision1," EPRI Report TR-103836, July 1994.

EPRI Report TR-103836 discusses fatigue in vessel flange in subsection 4.2.2.9. This subsection discusses thermal and mechanical fatigue cycling of the vessel flange, sampling of fatigue usage factors, and more detailed calculation results. The concluding paragraph states, "The low fatigue usage factors, coupled with successful operating experience, leads to the conclusion that fatigue will not be a significant age related degradation mechanism for the vessel flange during the license renewal period. This conclusion applies to all vessel flange designs."

Our review of the original RPV vendor calculations indicates that the CUF for the Peach Bottom Units 2 & 3 vessel flange was 0.00 for a 40-year life, which is insignificant and therefore is not an issue for Peach Bottom license renewal. Therefore, Table 3.1-1 of the PBAPS LRA does not identify cumulative fatigue damage as an aging effect for vessel flange.

RAI 3.1-3

Void swelling is not identified as an aging effect for any component of the reactor pressure vessel and internals. The applicant is requested to supply the peak neutron fluence for the reactor internals at the end of the license renewal term. Using this neutron fluence as basis, provide data that indicates void swelling is not an aging effect during the license renewal term. If it is an aging effect, identify the aging management program that will ensure the function of the internals is not degraded (result in cracking or change in critical dimensions) during the license renewal term.

Response:

Void swelling is not an aging effect. Rather, it is an aging mechanism, and the effects of concern would be swelling or cracking. EPRI TR-107521, "Generic License Renewal Technical Issues Summary", EPRI, April 1998, addresses data gathered from Liquid-Metal-Cooled Fast Breeder Reactors (LMFBRS), and how it may possibly be related to a PWR component (baffle-former bolt) that is in almost direct contact with the fuel in a PWR. A BWR does not have components located in a similar location, and thus, can reasonably be expected to experience less fluence. Past studies of void swelling by ANL, ORNL, HEDL and GE have shown that the threshold fluence for void swelling is approximately 1 X 10^{22} n/cm^2, which is well in excess of the fluences experienced by BWR components. Secondly, the EPRI report notes that field experience does not support void swelling being a significant issue. The lowest temperature for which this phenomenon is conjectured to occur is 300^{0}C (572^{0}F), which is higher than the internals that either Peach Bottom unit will experience. Further, the RPV and Internals ISI program that implements the NRC staff approved BWRVIP program for BWR internals addresses the key aspects of the internals components and provides inspection criteria where appropriate to manage aging. The BWRVIP Program that is implemented at Peach Bottom plant is adequate to address aging of the internals.

RAI 3.1-4

Table 3.1-1 of the LRA indicates that the CASS components in jet pump assemblies and CASS fuel supports have no aging effects requiring management because the ferrite content is less than 20 vol.%. However, according to the criteria stated in the May 19, 2000, NRC letter from C. I. Grimes to D. Walters, if the molybdenum content of these components is not low (0.5 wt.%) and the ferrite content is greater than 14 vol.%, these components are considered susceptible to thermal embrittlement. CASS components with niobium are also considered susceptible to thermal embrittlement.

For all CASS components that are susceptible to significant thermal embrittlement, the applicant may perform a flaw tolerance analysis. The flaw tolerance analysis should follow the methodology and criteria in Code Case N-481. Piping and reactor vessel internals that are potentially susceptible to thermal embrittlement and can not satisfy the flaw tolerance criteria must be inspected with a technique that is capable of detecting a quarter thickness crack with a 6-to-1 aspect ratio in the CASS component.

Describe which CASS components are susceptible to thermal embrittlement and will require a flaw tolerance analysis? Describe the proposed aging management program for components that are susceptible to thermal embrittlement and cannot demonstrate adequate flaw tolerance?

Response:

Research on the jet pump assembly and orificed fuel support materials indicates that they were manufactured to the low moly ASTM SA 351, Grade CF-8. All of these castings at Peach Bottom are statically cast, except the jet pump inlet-mixer adapter castings that are centrifugally cast. Calculated delta ferrite percentages (based on ASTM A800 and the certified material test reports) indicate that the maximum percentage of delta ferrite in any of the statically cast components is below 20%.

According to Table 2, "CASS Thermal Aging Susceptibility Screening Criteria," stated in the May 19, 2000 NRC letter from C.I.Grimes to D.Walters, grade CF8, low Moly content and <20% delta ferrite material are not susceptible to thermal aging for statically or centrifugally cast components. Table 3.1-1 of the LRA reflects this result.

RAI 3.1-5

The CASS components in the jet pump assemblies and CASS fuel supports may experience neutron fluence greater than 10^{17} n/cm^2 and become susceptible to neutron irradiation embrittlement. Irradiation embrittlement of CASS components becomes a concern only if cracks are present in the components. Industry wide experience shows that significant cracking has not been observed in CASS jet pump assembly components. Please describe an aging management program to confirm that the CASS jet pump assembly components and fuel supports are not susceptible to cracking.

Response:

The Plant Hatch License Renewal Safety Evaluation Report, NUREG-1803, section 3.2.3 staff evaluation of effects of aging for reactor assembly system under neutron and thermal embrittlement acknowledges that irradiation embrittlement of CASS components becomes a concern only if cracks are present in the components. Our review of the industry experience and plant experience has not identified any cracking in these components. Further, the BWRVIP-41 report, "BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines", requires inspection of several jet pump assembly welds, which are more susceptible to cracking than the CASS components and will therefore serve as an indication of the potential need for more extensive inspections later in life.

In the case of the orificed fuel support (OFS), per BWRVIP-06, Safety Assessment of BWR Internals, section 2.9, the OFS is a casting with no welds, and as such is not expected to crack. However, due to its proximity to the core, irradiation embrittlement may make the OFS more susceptible to cracking from impact loads, such as a dropped fuel bundle. Since this is event related, corrective action would include inspection for damage prior to resuming operation. Section 2.9.2 of BWRVIP-06 states, "visual inspections at seven facilities have found no indications of cracking in OFS castings". As such, no aging management program is necessary to manage the effects of irradiation.

The BWRVIP guidelines are implemented at PBAPS through the Reactor Pressure Vessel and Internals ISI program, which is augmented to the PBAPS 10-year ISI program. The PBAPS LRA, Appendix B.2.7, RPV and Internals ISI Program credits BWRVIP-41 for inspection of jet pump assembly.

Based on the above, we believe the RPV and Internals ISI program adequately manages the aging effects of irradiation embrittlement.

RAI 3.1-6

The applicant identifies cracking as an aging effect for stainless steel components in the reactor coolant system exposed to reactor coolant environment. Identify whether the cracking results from stress corrosion or thermal fatigue, identify the butt weld locations within the system and the pipe size for all effected components. For components less than 4 inches in diameter, identify whether the components are susceptible to stress corrosion cracking or thermal fatigue resulting from turbulent penetration or thermal stratification, and identify the aging management program for detecting cracking.

Response:

This issue was researched to identify all Class 1 butt-welded piping and components less than 4 inches in diameter within the scope of license renewal. The following Class 1 butt-welded applications were identified:

Reactor Pressure Vessel Head Vent 4" x 2" Reducer

The reactor pressure vessel head vent is a 4-inch flange connection, with the downstream flange welded to a 4" x 2" reducer. The flange, reducer and piping material is carbon steel and therefore not susceptible to stress corrosion cracking. This reducer introduces a 2-inch butt-weld connection on the downstream side. The remainder of the downstream head vent piping is socket-welded. The reactor pressure vessel head vent 4" x 2" reducer is exposed to steam during normal plant operation. Based on the guidance of EPRI MRP-24, "Interim Thermal Fatigue Management Guideline," this piping is not susceptible to thermal fatigue resulting from turbulent penetration or thermal stratification.

The Aging Management Activities identified for this piping are Reactor Coolant System Chemistry (Appendix B.1.2) and ISI (Appendix B.1.8) as defined in the PBAPS LRA Table 3.1-4.

Inboard Main Steam Drain Header Through Primary Containment

This line is a 3-inch diameter carbon steel header that collects condensate from the HPCI, RCIC and Main Steam lines inside containment. The individual drain line from the RCIC steam line is a 1-inch socket-welded line. The individual drain line from the HPCI steam line is a 1.5-inch socket-welded line. The individual drain lines from the Main Steam lines to the 3-inch header are 2-inch socket-welded lines. The line becomes 3-inch butt-welded after all the individual drain lines tie in, just before the line penetrates the primary containment.

This piping is carbon steel and therefore not susceptible to stress corrosion cracking. The 3-inch butt-welded portion of the drain line is well downstream of the process steam lines, connected by the 1", 1.5" or 2" socket-welded drain lines as described above. Therefore, based on the guidance of EPRI MRP-24, "Interim Thermal Fatigue Management Guideline," the 3-inch butt-welded piping is not susceptible to thermal fatigue resulting from turbulent penetration or thermal stratification.

The Aging Management Activities identified for this piping are Reactor Coolant System Chemistry (Appendix B.1.2), ISI (Appendix B.1.8), and FAC Program (Appendix B.1.1) as defined in the PBAPS LRA Table 3.4-1.

Steam Supply to the RCIC Turbine

The steam supply for the RCIC turbine comes from a branch connection off of a main steam line inside containment. The RCIC steam supply line passes through its own containment penetration to supply steam to the RCIC turbine located outside containment. The RCIC steam supply line is a 3-inch carbon steel line from the connection with the main steam system to the outboard containment isolation valve. This carbon steel line is not susceptible to stress corrosion cracking. This piping is exposed to steam during normal plant operation. Based on the guidance of EPRI MRP-24, "Interim Thermal Fatigue Management Guideline," this piping is not susceptible to thermal fatigue resulting from turbulent penetration or thermal stratification.

The Aging Management Activities identified for this piping are Reactor Coolant System Chemistry (Appendix B.1.2) and ISI (Appendix B.1.8) as defined in the PBAPS LRA Table 3.2-4.

RAI 3.1-7

The applicant identifies loss of material as an aging effect for stainless and carbon steel components in the reactor pressure vessel instrumentation system. The applicant identifies (a) RCS Chemistry Program to mitigate this effect and (b) ISI Program, which includes periodic hydrostatic pressure tests, to confirm the integrity of these components. These pressure tests are not adequate to confirm the effectiveness of the RCS Chemistry Program to prevent loss of material. Please describe an aging management program to confirm the effectiveness of the RCS Chemistry Program, i.e., to confirm that the stainless steel and carbon steel components in the reactor pressure vessel instrumentation system are not susceptible to loss of material.

Response:

The majority of the components in the reactor pressure vessel instrumentation system are constructed of stainless steel, so significant loss of material would not be expected in the reactor coolant or steam environment. Loss of material is conservatively considered as an applicable aging effect for these stainless steel components, and we believe that the RCS Chemistry and ISI Program aging management activities are adequate to manage this aging effect. Plant specific and industry operating experience does not indicate a problem with failure due to loss of material of these stainless steel components.

The only carbon steel piping in the reactor pressure vessel instrumentation system is the wide range level instrument tap coming off of the two-inch carbon steel reactor head vent line. This one-inch line is carbon steel from the two-inch head vent line to a flange connection with the stainless steel instrument line. The subject one inch carbon steel pipe is a six inch long nipple, installed in a socket welded reducing bushing in a two inch socket welded tee in the reactor head vent line. The tee is located a short distance from the vessel head vent flange connection. PBAPS has not experienced failure due to loss of material in this line. The review of industry experience has not identified an issue with failure due to loss of material in this line.

This small section of carbon steel piping is normally exposed to a saturated steam environment. We believe that the RCS Chemistry and ISI Program aging management activities are adequate to manage loss of material in this section of piping.

RAI 3.1-8

(a) Loss of material due to galvanic corrosion can occur when two dissimilar metals (i.e., carbon steel and stainless steel) are in contact in the presence of oxygenated water. The applicant is requested to identify whether the carbon steel piping of the reactor pressure vessel instrumentation system is connected to stainless steel components. If so, then does the aging effect of loss of material include damage due to galvanic corrosion? The applicant has identified the RCS Chemistry Program to mitigate this aging effect. Please describe an aging management program to confirm the effectiveness of the RCS Chemistry Program to prevent loss of material from galvanic corrosion.

(b) The applicant is requested to identify whether the carbon steel piping of the reactor recirculation system is connected to stainless steel components. If so, then does the aging effect of loss of material include galvanic corrosion? The applicant has identified the RCS Chemistry Program to mitigate this aging effect. Please describe an aging management program to confirm the effectiveness of the RCS Chemistry Program to prevent loss of material from galvanic corrosion.

Response:

(a) The steam side of the wide range level instrument tap comes off the reactor head vent line. This instrument line is carbon steel from the head vent line to a flange connection with a stainless steel instrument line. The aging effect of loss of material includes potential damage due to galvanic corrosion. As indicated in Table 3.1-3, the RCS Chemistry (LRA Appendix B.1.2) and ISI Program (LRA Appendix B.1.8) aging management activities manage this aging effect. The RCS Chemistry aging management activity monitors and controls conductivity, which acts to minimize the rate of galvanic corrosion. Industry and plant operating experience has determined that galvanic corrosion has not been a problem for boiling water reactors within the reactor coolant pressure boundary. The ISI Program aging management activity includes periodic hydrostatic pressure tests that confirm the integrity of the flanged connection. A review of plant specific operating experience does not indicate failure or leakage of this piping due to loss of material. The ISI pressure tests confirm the effectiveness of the RCS Chemistry Program to prevent loss of material from galvanic corrosion.

(b) The only carbon steel piping and valves included in the Reactor Recirculation system are the piping and valves associated with the reactor vessel bottom head drain. The bottom head drain line is a 2-inch carbon steel line from the reactor bottom head to a connection with a 2-inch stainless line. The aging effect of loss of material includes potential damage due to galvanic corrosion. As indicated in Table 3.1-4, the RCS Chemistry (LRA Appendix B.1.2) and ISI Program (LRA Appendix B.1.8) aging management activities manage this aging effect. The RCS Chemistry aging management activity monitors and controls conductivity, which acts to minimize the rate of galvanic corrosion. The ISI Program aging management activity includes periodic hydrostatic pressure tests that confirm the integrity of the piping connections. A review of plant specific operating experience does not indicate failure or leakage of this piping due to loss of material. The ISI pressure tests confirm the effectiveness of the RCS Chemistry Program to prevent loss of material from galvanic corrosion.

RAI 3.1-9

The valve bodies, valve bonnets, and valve closure bolting in the reactor pressure vessel instrumentation system are subject to ASME Code fatigue analysis. But the applicant has not identified cumulative fatigue damage as an aging effect for these components. Provide the technical basis for not considering cumulative fatigue damage as an aging effect for these components.

Response:

RPV Instrumentation system piping is designed to the requirements of ANSI B31.1. This code applies only to piping and does not require explicit fatigue analyses. Therefore, CUF values were not calculated for this system piping. PBAPS LRA section 4.3.3 addresses piping and component fatigue and thermal cycles for piping designed to requirements of ANSI B31.1.

RAI 3.1-10

According to NUREG-0313, Rev. 2, a CASS component is susceptible to stress corrosion cracking if the carbon content is greater than 0.035 wt% or ferrite content less than 7.5 vol.%. In a statically cast CASS component (i.e., pump casing), the ferrite distribution is not uniform and could be below 7.5 vol.% at some locations on the inside surface of the component. In addition, if the ferrite content of the weld metal used to perform repair at the inside surface of the pump casing is less than 7.5 vol.%, the pump casing is susceptible to stress corrosion cracking. The applicant is requested to present technical justification for not including cracking as an aging effect for the CASS pump casings in the reactor recirculation system.

Response:

Cracking is considered an applicable aging effect for the pump casings in the Reactor Recirculation system. This aging effect was inadvertently excluded from LRA Table 3.1-4. In the first row of Table 3.1-4, the Component Group "Casting and Forging" should include both Pump Casings and Valve Bodies. The aging effect of cracking will be managed by the RCS Chemistry and ISI Program aging management activities. The first part of Table 3.1-4 is included below to show the change.

3.1.4 Reactor Recirculation System

Table 3.1-4 Aging Management Review Results for Component Groups in the Reactor Recirculation System

Component Group	Component Intended Function	Environment	Materials of Construction	Aging Effect	Aging Management Activity
Casting and Forging • Valve Bodies • ***Pump Casings***	• Pressure Boundary	Reactor Coolant	Stainless Steel	Cracking	• BCS Chemistry (B.1.2) • ISI Program (B.1.8)
Casting and Forging • Valve Bodies	• Pressure Boundary	Reactor Coolant	Carbon Steel	Loss of Material	• BCS Chemistry (B.1.2) • ISI Program (B.1.8)
Casting and Forging • Pump Casings	• Pressure Boundary	Reactor Coolant	Cast Austenitic Stainless Steel	Loss of Fracture Toughness	• ISI Program (B.1.8)
Casting and Forging • Valve Bodies	• Pressure Boundary	Reactor Coolant	Stainless Steel	Loss of Material	• BCS Chemistry (B.1.2) • ISI Program (B.1.8)
Casting and Forging • Valve Bodies • Pump Casings	• Pressure Boundary	Sheltered	Stainless Steel, Carbon Steel, Cast Austenitic Stainless Steel	None	• Not Applicable

RAI 3.1-11

The applicant is requested to present an evaluation of the BWR industry-wide response to NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems." The staff would specifically like to know whether the applicant, in response to the NRC Bulletin, identified any unisolable sections of piping connected to the Peach Bottom RCS that can be subjected to stresses from turbulent penetration, temperature stratification, or temperature oscillations induced by leaking valves. The staff needs this information to assess the effectiveness of the ISI Program, presented in Section B.1.8 of the LRA, to manage cracking of the reactor coolant system components.

Response:

The Exelon response to NRC Bulletin 88-08 was provided to the NRC by letter dated September 16, 1988. As indicated in the response, the design of the Peach Bottom station does not contain any unisolable sections of piping that are potentially subject to thermal cycling fatigue from cold water leaks into the RCS during normal operation. The response concludes that the Peach Bottom station does not contain any unisolable sections of RCS piping that can be subject to stresses of the type defined in the Bulletin.

RAI 3.1-12

Components of the reactor recirculation system, such as piping and recirculation pump subcomponents (casing, cover, seal flange and closure bolting, valve bodies, bonnets and closure bolting) are subject to cumulative fatigue damage due to plant heatup, cooldown, and other operational transients. Cumulative fatigue damage has not been identified as an aging effect for any of the component in the reactor recirculation system. Provide the technical basis for excluding cumulative fatigue damage as an aging effect for the reactor recirculation system components that are within the scope of license renewal.

Response:

Cumulative fatigue damage has been addressed in TLAA Section 4.3.

Cumulative fatigue for Reactor recirculation piping designed to ASME Section III, class 1 requirements is addressed in the TLAA section 4.3.3.1. Reactor recirculation system piping designed to the requirements of ANSI B31.1 does not require explicit fatigue analyses. Therefore, CUF values were not calculated for this system piping. PBAPS LRA section 4.3.3.2 addresses piping and component fatigue and thermal cycles for piping designed to requirements of ANSI B31.1.

RAI 3.1-13

a) The applicant's reactor coolant system chemistry program is based on the guidance presented in EPRI TR-103515, "BWR Water Chemistry Guidelines, 2000 Revision." The reviewers note that the staff has not approved EPRI TR-103515, 2000 Revision, for generic use. The latest revision reviewed by the staff is the 1996 revision (Reference: September 18, 1998 letter from D.S. Hood, NRC to J.H. Mueller, Niagara Mohawk Power Corporation). Therefore, the applicant is requested to identify the changes in the water chemistry program that result from the use of the guidelines from the1996 Revision to the 2000 Revision of EPRI TR-103515.

b) To determine the effectiveness of the EPRI TR-103515 BWR water chemistry guidelines, identify components at Peach Bottom that have had stress corrosion cracking or loss of material since the EPRI TR-103515 water chemistry guidelines were instituted at Peach Bottom. Identify the changes in water chemistry that have been instituted to eliminate or mitigate cracking or loss of material in these components.

c) The reactor coolant system chemistry AMP, presented in Section B.1.2 of the LRA, continuously monitors coolant conductivity, and measures the impurities such as chlorides and sulfates only when the conductivity measurements indicate presence of abnormal conditions. Does EPRI TR 103515, 2000 Revision guidelines require that the sulfates and chlorides be measured daily and continuous monitoring of the desolved oxygen concentration in the reactor feedwater/condensate system and the control rod drive water?

d) The applicant is requested to provide information about whether Peach Bottom Units 1 and 2 employ hydrogen water chemistry with NMCA (noble metal chemical application) applied? If so, then according to EPRI TR-103515, 2000 Revision guidelines, which parameters should be monitored to assess the effectiveness of this water chemistry? How often these parameters should be measured and what are the required limits for them? Note that BWRVIP-62, "BWR Vessel and Internals Project, Technical Basis for Inspection Relief for BWR Internal Components with Hydrogen Injection." recommends monitoring of electrochemical potential and hydrogen-to-oxygen molar ratio for assessing the effectiveness of HWC with NMAC applied.

e) What changes in the PBAPS Technical Specifications are made to account for the use of EPRI TR-103515, 2000 Revision guidelines?

Response:

a) Peach Bottom Atomic Power Station's (PBAPS) reactor water chemistry control program is based on EPRI TR-103515, "BWR Water Chemistry Guidelines" – 2000 Revision. PBAPS believes that it is important to maintain the flexibility to modify its plant chemistry control program based on the collective industry operating experience of similar reactors. Therefore, over time, PBAPS expects to revise its plant chemistry control program to reflect changes in industry guidance presented in the EPRI BWR Water Chemistry Guidelines (TR-103515).

The 2000 revision of EPRI BWR Water Chemistry Guidelines differs from the 1996 revision in the following areas for Reactor Water – Power operation:

1. In the 2000 revision to the EPRI BWR Water Chemistry Guidelines, chlorides and sulfates no longer need to be measured on a daily basis provided that reactor water conductivity is trended to ensure that the action level 1 limits are not exceeded. At PBAPS, chloride and sulfate are measured 3 times per week, provided that reactor water conductivity remains below an administrative limit, which was set to assure that chlorides and sulfates action level 1 limits are not exceeded. This provides adequate assurance that chloride and sulfate levels are controlled below action level 1 limits. If the reactor water conductivity exceeds its administrative limit, chloride and sulfate sampling frequency is increased based on the significance of the transient. In this case, sampling frequency is at least once per day.

2. In the 2000 revision to the EPRI BWR Water Chemistry Guidelines, plants with HWC or HWC with Noble Metals Chemical Addition (NMCA) no longer need to measure ECP on a continuous basis. Even in the 1996 version of the EPRI BWR Water Chemistry Guidelines, alternate methods (e.g., Main Steam Line Radiation) could be used for estimating ECP. PBAPS is a HWC with NMCA plant that uses ECP and alternate methods for estimating ECP. PBAPS is not committed to measure ECP on a continuous basis and would use alternative methods if ECP measurements were not available.

3. The 2000 revision to the EPRI BWR Water Chemistry Guidelines allows Plants with HWC or HWC with NMCA to go to higher action level 2 and 3 levels for chloride and sulfate. Action level 2 was increased from >20 ppb to > 50 ppb and Action level 3 was increased from >100 ppb to > 200 ppb. This additional flexibility is allowed based on the increased protection of reactor coolant system and reactor assembly components provided by HWC or HWC with NMCA.

4. The 2000 revision to the EPRI BWR Water Chemistry Guidelines also added Reactor Water Iron as a new diagnostic parameter to its Reactor Water Chemistry Guidelines. PBAPS has implemented this change.

b) As stated in LRA Appendix B1.2 attribute 10, "As chemistry control guidelines were evolving in the industry, PBAPS experience with reactor coolant system chemistry was similar to that of the industry. Cracking attributed to IGSCC was found in stainless steel recirculation and RHR system piping and loss of material was found in the HPCI and RCIC carbon steel steam line drains. Portions of the 304 stainless steel recirculation system, RWCU, and RHR piping were replaced with more IGSCC resistant, low carbon, 316 stainless steel. The HPCI and RCIC steam drain lines were also replaced.

The RCS water chemistry is maintained based on the recommendations of EPRI TR-103515 that have been developed based on industry experience. These recommendations have been shown to be effective and are adjusted as new information becomes available. Since the pipe replacement and improvements to chemistry activities, the overall effectiveness of RCS chemistry activities is supported by the excellent operating experience of reactor coolant and main steam systems at PBAPS. For example, no IGSCC cracking has been identified in the recirculation system piping since it was replaced in 1985 and 1988. PBAPS implemented the EPRI chemistry guidelines in 1986 and has continued to revise plant procedures as the guidelines are updated. PBAPS uses the BWRVIP program to monitor the condition of reactor vessel internals. An annual summary report is sent to the NRC from the BWRVIP with results of BWR plant inspections.

c) Chloride and sulfate measurement frequency changes are discussed in part a) of this RAI response. The described analysis process will provide adequate assurance that chloride and sulfate levels are controlled below action level 1 limits.

PBAPS does have a continuous dissolved oxygen monitor on the condensate, feedwater and reactor water systems. Since under normal operations control rod drive water comes from the condensate system, an additional dissolved oxygen monitor is not provided on the control rod drive water system.

d) PBAPS is a HWC plant with NMCA applied. Peach Bottom Unit 2 applied NMCA during Refueling Outage 12 in October 1998 and on Unit 3 during Refueling Outage 12 in October 1999. After the startup following the refueling outage, when chemistry stabilized, HWC was placed in operation under NMCA on both units. Both plants have been operating on HWC since May 1997. In accordance with EPRI TR-103515, 2000 Revision of the BWR Water Chemistry Guidelines, PBAPS monitors the following parameters at the indicated frequency to assess the effectiveness of NMCA / HWC water chemistry:

Parameter	Frequency
RWCU Water ECP (1)	Continuous
Reactor Water Dissolved Oxygen (2)	Continuous
Reactor Water Conductivity	Continuous
Reactor Water Chloride	3 times per week (3)
Reactor Water Sulfate	3 times per week (3)
Reactor Water Zinc (4)	2 times per week
Reactor Water Co60 (4)	Weekly
HWC - hydrogen flow (2)	Daily
Feedwater flow (2)	Daily

(1) PBAPS presently has 2 ECP probes per unit. PBAPS may not replace these probes when they fail but instead use secondary measurements (Reactor water dissolved oxygen and HWC hydrogen flow / feedwater flow).

(2) Reactor water dissolved oxygen and HWC hydrogen flow / Feedwater flow are used as secondary ECP measurements and to calculate the Reactor Water hydrogen-to-oxygen molar ratio.

(3) As permitted by EPRI TR-103515, 2000 Revision of the BWR Water Chemistry Guidelines, this frequency has been adjusted from a daily frequency based on site-specific resource allocation needs after a correlation was established to Reactor Water Conductivity.

(4) Reactor Water Zinc and Co60 are monitored for Drywell Dose Rate control, not for NMCA / HWC water chemistry effectiveness. NMCA / HWC does have a significant impact on Drywell Dose Rates requiring the monitoring of these parameters.

PBAPS adheres to the EPRI TR-103515, 2000 Revision of the BWR Water Chemistry Guideline Limits for these parameters as shown below:

	Action Levels		
Parameter	1 (1)	2 (2)	3 (3)
Reactor Water Conductivity (μS/cm)	>0.3	>1.0	>5.0
Reactor Water Chloride (ppb)	>5	>50	>200
Reactor Water Sulfate (ppb)	>5	>50	>200

(1) Action Level 1 is the value of parameter which engineering judgment indicated that long-term system reliability may be threatened. If exceeded:
   (a) Restore the parameter to below Action Level 1 values as soon as practicable or
   (b) If not restored within 96 hours, perform a review to assess the impact on long-term reliability.

(2) Action Level 2 is the value of a parameter that represents the range outside of which data or engineering judgment indicated that significant degradation of the system may occur in the short term. If exceeded:
   (a) As soon as practicable take corrective action to reduce the parameter to below the Action Level 2 value or
   (b) If not restored within 24 hours, an orderly plant shutdown shall be initiated.
   (c) If it is foreseen that the parameter will be below the Action Level 2 value within the time period required for an orderly shutdown, power operation can be maintained.
   (d) Following a unit shutdown caused by exceeding an Action Level 2 value, a review of the incident shall be performed.

(3) Action Level 3 is the value of a parameter that represents the range outside of which data or engineering judgment indicated that it is inadvisable to continue to operate the plant. If exceeded:

(a) Immediately initiate a orderly unit shutdown and
(b) Reduce the parameter to below the Action Level 3 value as quickly as possible.

Other Water Chemistry Parameters with administrative limits

Parameter	Admin Limit (1)
Reactor Water ECP (mv, SHE)	< -230
Reactor Water Dissolved Oxygen (ppb)	< 10

(1) If an administrative limit is exceeded, take corrective action to restore the parameter to below the administrative limit value as soon as practicable.

PBAPS also complies with the recommendations of BWRVIP-62, "BWR Vessel and Internals Project, Technical Basis for Inspection Relief for BWR Internal Components with Hydrogen Injection," by monitoring of ECP (electrochemical potential) and hydrogen-to-oxygen molar ratio to assess the effectiveness of HWC with NMAC applied. As described in BWRVIP-62, PBAPS may not replace its ECP probes when they fail but instead use secondary measurements (Reactor water dissolved oxygen and HWC hydrogen flow / feedwater flow).

e) PBAPS was not required to make any changes to its Technical Specifications to account for the use of EPRI TR-103515, 2000 Revision of the BWR Water Chemistry Guidelines. The EPRI TR-103515, 2000 Revision of the BWR Water Chemistry Guidelines are implemented with station procedure CH-10, "Chemistry Goals".

RAI 3.1-14

In Section B.2.7, "Reactor Pressure Vessel and Internals ISI Program," of the LRA, the applicant stated that the vessel internals requiring aging management within the scope of license renewal are shroud, shroud supports, access hole covers, core support plate, core P/SLC line, top guide, core spray piping and spargers, control rod guide tubes, jet pump assemblies, CRDH guide tubes, in-core housing guide tubes, and dry tubes. The applicant has not submitted information about any repair to core shroud or other internals, but NUREG-1544, "Status Report: Intergranular Stress Corrosion Cracking of BWR Core Shrouds and Other Internal Components," published in 1994, refers to the PECO Energy Company's submittal of the Peach Bottom core shroud repair designs to NRC for review. The applicant is requested to provide information about whether the Peach Bottom core shrouds and other internals have been repaired, and if so then whether the repair hardware for those components is within the scope of the reactor pressure vessel and internals ISI program.

Response:

NUREG-1544 provided the shroud repair modification for NRC review. However this repair was not implemented at either PBAPS unit.

RAI 3.1-15

To evaluate whether the reactor materials surveillance program presented in Section B.1.12 of the LRA provides sufficient data for monitoring the extent of neutron irradiation embrittlement during the license renewal period, the staff requests that the applicant determine whether the existing Peach Bottom reactor surveillance program or the integrated surveillance program would be revised to satisfy the following attributes:

> Capsules shall be removed periodically to determine the rate of embrittlement and at least one capsule with a neutron fluence not less than once or greater than twice the peak beltline neutron fluence must be removed before the expiration of the license renewal period.
>
> Capsules shall contain material to monitor the impact of irradiation on the limiting beltline materials and must contain dosimetry to monitor neutron fluence.
>
> If capsules are not being removed from Peach Bottom during the license renewal period, the applicant shall supply operating restrictions (i.e., inlet temperature, neutron spectrum and flux) to ensure that the RPV is operating within the environment of the surveillance capsules, and must supply ex-vessel dosimetry for monitoring neutron fluence.

The applicant has indicated in Section B.1.12 of the LRA that it plans to implement the provisions of the Integrated Surveillance Program (ISP) as described in BWRVIP-78. The staff requests that the applicant provide the schedule for implementing the ISP at Peach Bottom. The staff also request that the applicant indicate how the proposed ISP would satisfy the ISP criteria in Appendix H, 10 CFR Part 50 and the attributes discussed above.

Response:

The BWRVIP has developed an ISP and submitted it to NRC for review and approval. The ISP is documented in BWRVIP-78, "BWR Vessels and Internals Project: BWR Integrated Surveillance Program Plan," issued December 1999, and it's companion document, BWRVIP-86, "BWR Vessels and Internals Project: BWR Integrated Surveillance Program Implementation Plan." BWRVIP-78 and BWRVIP-86 were found acceptable for the current term by the NRC as documented in an SER dated February 1, 2002 from Bill Bateman of the NRC to Carl Terry, BWRVIP Chairman. One of the provisions of the ISP is for surveillance capsule material withdrawal and testing during the license renewal period. A revision to these BWRVIP documents to include license renewal is in process and will be submitted to the NRC in the near future. As noted in section 2.1 of BWRVIP-78, the ISP complies with the provisions of 10CFR50 Appendix H. The ISP currently provides for 13 capsules to be available for testing during the renewal period for the BWR fleet.

Exelon is aware of the provisions of Appendix H, and understands that the RPV must be operated within parametric limits that assure vessel integrity with regard to embrittlement and fracture toughness. However, there is not yet a demonstrated need to provide operating restrictions. Should the ISP be approved by the NRC, PBAPS will be bounded by the 13 representative capsules that are available for testing during the renewal period for the BWR fleet.

Exelon plans to implement the provisions of the ISP currently described in BWRVIP-78 and BWRVIP-86. Should the ISP not be approved by the NRC, or should it be modified such that PBAPS is not covered by the ISP, then Exelon will develop a RPV material surveillance program for the period of extended operation. This plant-specific program, if needed, will include the following actions:

- Capsules will be removed periodically to determine the rate of embrittlement and at least one capsule with a neutron fluence not less than once or greater than twice the peak beltline neutron fluence will be removed before the expiration of the license renewal period.
- Capsules will contain material to monitor the impact of irradiation on the limiting beltline materials and must contain dosimetry to monitor neutron fluence.
- If capsules are not being removed from PBAPS during the license renewal period, the applicant will supply operating restrictions (i.e., inlet temperature, neutron spectrum and flux) to ensure that the RPV is operating within the environment of the surveillance capsules, and must supply ex-vessel dosimetry for monitoring neutron fluence.

RAI 3.1-16 - UFSAR Update

The reviewers found that the summary of the reactor coolant system chemistry program in Section A.1.2 of the LRA is adequate, except that it does not identify the supporting documents (e.g., EPRI water chemistry guidelines). The applicant is requested to include in the UFSAR update the supporting documents by reference in Section A.1.2. The revision of the water chemistry guidelines need not be included in the UFSAR update.

Response:

Section A.1.2 is revised to read as follows:

A.1.2 Reactor Coolant System Chemistry

PBAPS reactor coolant system (RCS) chemistry activities manage loss of material and cracking of components exposed to reactor coolant and steam through measures based on EPRI TR-103515, "BWR Water Chemistry Guidelines," that monitor and control reactor coolant chemistry. These activities include monitoring and controlling of reactor coolant water chemistry to ensure that known detrimental contaminants are maintained within pre-established limits. Reactor coolant is monitored for indications of abnormal chemistry conditions. If such indications are found, then measurements of impurities are conducted to determine the cause, and actions are taken to address the abnormal chemistry condition. Whenever corrective actions are taken to address an abnormal chemistry condition, sampling is utilized to verify the effectiveness of these actions. The RCS chemistry activities provide reasonable assurance that intended functions of components exposed to reactor coolant and steam are not lost due to loss of material or cracking aging effects.

RAI 3.1-17 - UFSAR Update

The applicant describes the Reactor Materials Surveillance Program as an existing program in Section A.1.12 of the LRA, but does not include a summary of the BWR Integrated Surveillance Program, which the applicant intends to use at Peach Bottom. The applicant is requested to include information about the BWR Integrated Surveillance Program, which should include reference to BWRVIP reports.

Response:

Section A.1.12 description has been revised to include information about the BWR Integrated Surveillance Program, which is one alternative that may be used at PBAPS to comply with 10CFR50, Appendix H. The revision to Section A.1.12 is provided here for your convenience:

A.1.12 Reactor Materials Surveillance Program

The PBAPS Reactor Materials Surveillance (RMS) program manages loss of fracture toughness in the reactor pressure vessel beltline region consistent with the requirements of 10 CFR 50, Appendix H and ASTM E185. Compliance with 10CFR50, Appendix H may be demonstrated either through an NRC approved site-specific program or an integrated surveillance program that meets the technical requirements documented within BWRVIP-78. The RMS program provides for periodic withdrawal and testing of in-vessel capsules to monitor the effects of neutron embrittlement on the reactor vessel beltline materials. The results of this testing are used to determine plant operating limits. The RMS program contains sufficient dosimetry and materials to monitor irradiation embrittlement during the period of extended operation and provides reasonable assurance that aging effects are detected and addressed prior to loss of intended function.

RAI 3.1-18

The applicant has identified two aging management programs (AMPs) that are dependent upon the BWRVIP's generic AMPs. These plant-specific AMPs are the "Reactor Pressure Vessel and Internals ISI Program" (Section B.2.7), and "Reactor Materials Surveillance Program" (Section B.1.12). In most instances, the staff's safety evaluations (SEs) of the applicable BWRVIP reports and their associated license renewal appendices, for which the applicant is referencing, contain generic open items and recommendations and applicant-specific license renewal action items. The staff requests that the applicant identify and discuss how the applicant is addressing, in a plant-specific manner, each generic open item and recommendation, and applicant-specific action items, in the staff's SEs for these BWRVIP reports and related license renewal appendices listed below. Specifically, but not necessarily limited to, the applicant should address the following open items from the referenced staff SEs:

A. As described in the open item in the safety evaluation for BWRVIP-18, when the applicant performs UT or VT inspection of BWR Core Spray Internals, the applicant should include the inspection uncertainties in measuring the flaw length by UT or VT and the value of the uncertainties used in the flaw evaluation should be demonstrated on a mock up.

B. The applicant should confirm that the hold down bolts will be inspected in accordance with the staff's safety evaluation for BWRVIP-25.

C. The applicant should confirm that, when the inspection tooling and methodologies are developed that allow the welds in the lower plenum to be accessible, the applicant will inspect these welds with the appropriate NDE method, in order to establish a baseline for these welds, and that an appropriate re-inspection schedule, based on appropriate safety considerations, as established by the BWRVIP in a revised BWRVIP-38 report, will be followed. Until this revision to the BWRVIP-38 report is made, the applicant is to commit to inspecting the supports and provide inspection guidance as discussed above.

D. Pending resolution of the open item in the BWRVIP-41 guidelines, the applicant should describe the type of inspection to be used for the thermal sleeve welds which are capable of detecting IGSCC, and to provide an inspection schedule and scope as discussed.

E. As discussed in the final safety evaluation for BWRVIP-47, the staff believes that an initial baseline inspection should be comprehensive, and include all safety-significant locations and components that are practicable to inspect, based on tooling available. Further, the staff believes that the re-inspection schedule and scope, based on the performance and results of the initial baseline inspections, should be addressed in the BWRVIP-47 report. Until BWRVIP-47 is resolved, the applicant is to describe the type of inspection and to provide an inspection schedule and scope as discussed.

F. The applicant should provide a response to the Action Items in the staff's SER for the BWRVIP-74.

G. The applicant should address all applicable plant-specific open items in the staff's BWRVIP-78/-86 SE.

In addition, the applicant should describe the BWRVIP-generic and applicant-specific processes for ensuring that the BWRVIP generic AMPs, as modified to address the staff's SE's generic open items and recommendations and applicant-specific action items, will be implemented during the license renewal term. Further, the applicant should confirm whether all the BWRVIP reports, including all appendices and revisions that are referenced in Sections B.2.7 and B.1.12, will be included in the UFSAR supplement (Appendix A of the LRA).

Response:

Exelon has evaluated the RPV and Internals ISI program for its applicability to PBAPS Units 2 and 3 design, construction, and operating experience, including the applicant action items associated with BWRVIP reports as well as any exemptions to the action items, and has established that the BWRVIP reports bound the PBAPS Units 2 and 3 design. The RPV components, including the materials used for construction, are addressed by the BWRVIP inspection and evaluation documents. The plant operating parameters, including temperature, pressure, and water chemistry, are consistent with those used for the development of the inspection and evaluation documents.

PBAPS Units 2 and 3 are committed to follow the BWRVIP guidance. For open issues between the BWRVIP and NRC, Exelon will work as part of the BWRVIP to resolve these issues generically. When resolved, PBAPS will follow the BWRVIP recommendations resulting from that resolution. If PBAPS cannot follow the resolution, then PBAPS will notify the NRC in accordance with the BWRVIP commitment (i.e., within 45 days of the NRC approval of the issue).

Exelon further confirms that the BWRVIP reports that are referenced in Appendix B.2.7 will be included in the UFSAR supplement Appendix A of the LRA. Information regarding Appendix B.1.12 is addressed in the response to RAI 3.1.17. The revision to Section A.2.7 is provided below for your convenience:

A.2.7 Reactor Pressure Vessel and Internals ISI Program

The BWR Vessels and Internals Project (BWRVIP) guidelines are implemented through the reactor pressure vessel and internals ISI program. The reactor pressure vessel and internals ISI program is that part of the PBAPS ISI program that provides for condition monitoring of the reactor vessel and internals using guidance provided by the BWRVIP and the BWR Owners Group alternate BWR feedwater nozzle inspection requirements. The PBAPS ISI program complies with requirements of an NRC approved Edition of the ASME Section XI Code, or approved alternative, and is implemented through a PBAPS specification. The PBAPS ISI program has been augmented to include various additional requirements, including those from the BWRVIP guidelines and the BWR Owners Group (BWROG) alternative to NUREG-0619 augmented inspection of feedwater nozzles for GL 81-11 thermal cycle cracking. The reactor pressure vessel and internals ISI program will be enhanced to assure that inspections are consistent with the relevant BWRVIP program criteria and NRC safety evaluation reports. The program utilizes early detection, evaluation and corrective actions that provide reasonable assurance that aging effects of reactor vessel components and internals will be detected and addressed prior to loss of intended function. Program enhancements are implemented as the BWRVIP guidelines are revised.

Reactor Pressure Vessel And Internals BWRVIP Document Applicability

Reactor Pressure Vessel Components	Reference
Reactor pressure vessel components	BWRVIP-74
Vessel shells	BWRVIP-05
Shroud support attachments	BWRVIP-38
Nozzle safe ends	BWRVIP-74
Core support plate	BWRVIP-25
Core ΔP / SLC nozzle	BWRVIP-27
Core spray attachments	BWRVIP-48
Jet pump riser brace attachments	BWRVIP-48
Other attachments	BWRVIP-48
CRDH stub tubes	BWRVIP-47
ICM Housing penetrations	BWRVIP-47
Instrument penetrations	BWRVIP-49
Reactor Internals Components	
Shroud support	BWRVIP-38
Shroud	BWRVIP-76
Core support plate	BWRVIP-25
Core ΔP / SLC line	BWRVIP-27
Access hole covers	(Note 1)
Top guide	BWRVIP-26
Core spray lines	BWRVIP-18
Core spray spargers	BWRVIP-18
Jet pump assembly	BWRVIP-41
CRDH stub tubes	BWRVIP-47
CRDH guide tubes	BWRVIP-47
In-core housing guide tubes, LPRM & WRNMS dry tubes	BWRVIP-47
Note 1. GE SIL 462 for Unit 2 only.	

3.2 Aging Management of Engineered Safety Feature Systems (ESF)

3.2.4 Reactor Core Isolation Cooling System (RCIC)

RAI 3.2.4-1

Given the potentially corrosive nature for wetted gas environments, discuss whether loss of material by pitting or general corrosion is an applicable effect for the surfaces of bronze RCIC valve bodies that are exposed to these environments. Provide your bases for your determination. If loss of material is an applicable aging effect for the bronze valve bodies exposed to wetted gas environments, an aging management program/activity must be proposed to manage the effect during the extended terms of operation for the PBAPS units.

Response:

There is only one bronze component in this environment for the RCIC system – it is the relief valve on the barometric condenser (RV-2 (3)-13C-121). The aging management review determined that loss of material is not an applicable aging effect for bronze in a wetted gas environment. This was based on the evaluation in the EPRI 1003056 "Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Rev. 3" that copper alloys are resistant to general corrosion in a gas environment and that pitting and crevice corrosion are not a concern because there is no potential for concentrating contaminants.

3.3 Aging Management of Auxiliary Systems

RAI 3.3-1

Clarify whether any of the auxiliary systems discussed in Section 3.3 of the LRA are within the category of seismic II over I SSCs as described in position C.2 of Regulatory Guide 1.29. Based on the information provided in Section 2.1.2.1 of the LRA, it appears that the applicant has included the pipe supports for seismic II over I piping systems in the scope of license renewal. However, the seismic II over I piping segments are not included within the scope of license renewal. The staff's concern is that seismic II over I piping, though seismically supported, would be subjected to the same plausible aging effects as safety-related piping. For example, depending on piping material, geometrical configuration, operation condition such as water chemistry, temperature, flow velocity, and external environment, erosion and corrosion may be plausible aging effects for some seismic II over I piping. Those effects, if not properly managed, could result in age-related failures and adversely impact the safety functions of safety-related SSCs. The applicant is requested to provide justification for not including the seismic II over I piping segments within the scope of license renewal. Specifically, the applicant is requested to address how plausible aging effects associated with those piping systems, if any, will be appropriately managed.

Response:

The response will be provided together with the responses to RAIs 2.1.2-3 and 2.1.2-4 by May 27, 2002.

RAI 3.3-2

Numerous ventilation systems discussed in Section 3.3 of LRA include elastomer components in the system. Normally ventilation systems contain elastomer materials in duct seals, flexible collars between ducts and fans, rubber boots, etc. For some plant design, elastomer components are used as vibration isolators to prevent transmission of vibration and dynamic loading to the rest of the system. The aging effects of concern for those elastomer components are change in material properties such as hardening and loss of strength and loss of material due to wear. The applicant has identified the aging effect of change in material properties. To manage that aging effect, the applicant relies on the periodic visual inspection and testing activities included in the aging management program, ventilation system inspection and testing activities. The applicant stated that the inspection interval is dependent on the component and the system in which it resides. The applicant also indicated that previous inspection and testing activities have detected damaged components and leakage in certain ventilation systems. The applicant is requested to clarify how it has considered the aging effect of loss of material due to wear for the applicable elastomer components. In addition, the applicant is requested to provide the frequency of the subject visual inspection and testing activities and to demonstrate the adequacy of the frequency of those inspection and testing activities to ensure that aging degradation will be detected before there is a loss of intended function.

Response:

The aging management review determined that the applicable aging effect for elastomer components in the ventilation systems was change in material properties due to loss of strength, resiliency, and elasticity. Loss of material due to wear was not identified as an applicable aging effect based on plant operating experience and operating conditions.

The deficiencies noted in the LRA Appendix B.2.3 "Ventilation System Inspection and Testing Activities" attribute 10 occurred in the 1980's before adequate PM activities were instituted in the early 1990's. Recent operating experience has been good, thereby supporting the current PM frequencies.

As stated in the Appendix B.2.3 attribute 5, components in the standby gas treatment system and the control room emergency ventilation system are inspected and tested annually. Additionally, PM activities for the battery room and emergency switchgear ventilation, control room fresh air supply, ESW booster pump room and diesel generator room are performed every two years. PM activities for the pump structure ventilation fans are performed every four years. Since no failures have been identified since the current PM activities have been instituted, the existing activities and frequencies are adequate to detect any aging effects prior to loss of intended function.

RAI 3.3-3

In Sections 2.3.3.18 and 3.3.18 of the LRA, the applicant describes the scope and the intended functions of cranes and hoists and their associated aging management review. However, in Section 4.0 of the LRA, the applicant has not identified a crane load cycle limit as a TLAA for the cranes within the scope of license renewal. Normally based on its design code, there is a specified load cycle limit at rated capacity over the projected life for the applicable crane. Therefore, it may be necessary to perform an evaluation of TLAA relating to crane load cycles estimated to occur up to the end of the extended period of operation. The applicant is requested to provide justification for not including the crane load cycle limit as an applicable TLAA.

Response:

Exelon's initial TLAA review pursuant to 10CFR54.21(c) identified fatigue of cranes as a potential plant-specific TLAA. Further review of current licensing basis documents showed that the cranes are designed to Service Class A, as defined in specification CMAA-70, 'Specification for Electric Overhead Traveling Cranes' and does not involve time-limited assumptions defined by the current term. Therefore, the potential TLAA does not meet the six (6) screening criteria defined in 10CFR54.3(a). On this basis we concluded that fatigue of cranes is not a TLAA.

The information provided above was discussed with NRC staff on January 22, 2002 telephone conversation. During this conversation, the staff restated its position that crane load cycles is a TLAA and it disagrees with Exelon's assertion it is not.

After further consideration, Exelon is amending its position and will include load cycles for the reactor building overhead bridge cranes, turbine hall cranes, emergency diesel generator bridge cranes, and the circulating water pump structure gantry crane as a TLAA in Section 4.7.4 of the LRA.

The load cycles for these cranes were evaluated for the period of extended operation. The cranes are predominantly used to lift loads which are significantly lower than their rated load capacity. Thus, the number of lifts at or near their rated load is low as compared to the design 20, 000 load cycles. For example, we conservatively estimated that the reactor building cranes will undergo less than 5000 load cycles in 60 years based on the number of qualified lifts during refueling outages, handling of spent fuel storage cask, and testing. The other cranes are expected to experience significantly less load cycles than the reactor building cranes. The cranes will continue to perform their intended function throughout the period of extended operation.

Therefore, the analyses associated with crane design, including fatigue, remain valid for the period of extended operation, in accordance with the requirements of 10CFR54.21(c)(1)(i).

RAI 3.3-4

Section 3.3.16, Emergency Diesel Generator contains Table 3.3.16 that outlines the aging management review results. For various components (valve bodies, strainer screens, piping, and vessels) the applicant identifies loss of material as an aging effect of carbon steel in moist environments such as closed cooling water and wetted gas. However, the applicant does not identify cracking as an aging effect in these same moist environments or in the outdoor environment. For example, for valve bodies intended to function as a pressure boundary in the closed cooling water environment, the applicant identified loss of material and cracking as aging effects for stainless steel, but identified only loss of material as an aging effect for carbon steel. In addition, although the applicant identifies loss of material and cracking as aging effects for carbon steel piping in the lubricating and fuel oil environments, the applicant does not identify loss of material as an aging effect for lubricating oil vessels or cracking as aging effects for lubricating and fuel oil vessels. The staff requests the applicant to provide information that supports the exclusion of the aging effects as described. The table below summarizes the component groups that the staff requests the applicant to address.

Page	Component Group	Component Intended Function	Environment	Materials of Construction	Excluded Aging Effect(s)
3-97	Casting and Forging: Valve Bodies	Pressure Boundary	Closed Cooling Water	Carbon Steel	Cracking
3-99	Casting and Forging: Strainer Screens	Filter	Wetted Gas	Carbon Steel	Loss of Material
3-109	Piping: Pipe	Pressure Boundary	Buried	Carbon Steel	Cracking
3-109	Piping: Pipe	Pressure Boundary	Closed Cooling Water	Carbon Steel	Cracking
3-110	Piping: Pipe	Pressure Boundary	Outdoor	Carbon Steel	Loss of Material and/or Cracking
3-111	Piping Specialties: Drain Traps Expansion Joints	Pressure Boundary	Wetted Gas	Carbon Steel	Cracking

Page	Component Group	Component Intended Function	Environment	Materials of Construction	Excluded Aging Effect(s)
3-111	Vessel: Expansion Tank	Pressure Boundary	Closed Cooling Water	Carbon Steel	Cracking
3-111	Vessel: Fuel Oil Day Tank	Pressure Boundary	Fuel Oil, Buried	Carbon Steel	Cracking
3-111	Vessel: Lubricating Oil Tank	Pressure Boundary	Lubricating Oil	Carbon Steel	Cracking
3-112	Vessel: Air Receivers	Pressure Boundary	Wetted Gas	Carbon Steel	Cracking
3-112	Vessel: Silencers	Pressure Boundary	Wetted Gas	Carbon Steel	Cracking

Response:

Cracking is not identified as an applicable aging effect in NUREG-1801 "Generic Aging Lessons Learned (GALL) Report" for carbon steel in any of the environments listed in the RAI. Under certain conditions, cracking due to vibration is an applicable aging effect for the emergency diesel generators as described in NRC Information Notices 89-07 and 98-43. For this reason, cracking was identified as an aging effect for certain components mounted on or near the diesel engines.

For the strainer screen, loss of material was not considered an applicable aging effect because it is in the diesel starting air system piping which accumulates moisture upstream of this strainer in the air receiver tank which is blown down daily to remove any moisture. Reference Appendix B.2.4 for a description of this activity. Thus, loss of material was not considered significant for this component.

RAI 3.3-5

Section 3.3.17, Suppression Pool Temperature Monitoring System of the application contains Table 3.3.17 that outlines the aging management review results. The applicant identifies loss of material as an aging effect for penetration sleeves in torus water. However, the applicant does not identify cracking as an aging effect for the penetration sleeves even though they provide a fission product barrier. The staff requests the applicant to provide information supporting the exclusion of cracking as an aging effect for penetration sleeves.

Response:

The thermowell sleeves penetrate the primary containment suppression chamber (torus) and are a part of the primary containment pressure boundary. For this reason, the thermowell sleeves are required to provide the fission product barrier intended function. Their aging effects were evaluated as a sub-component of the primary containment structure (torus) since there is no piping associated with them. The evaluation concluded that cracking due to stress corrosion cracking (SCC), and intergranular cracking (IGA) is not applicable as explained below. Cracking due to cumulative fatigue is a TLAA and is included in the evaluation of torus penetrations described in LRA Section 4.6.1.

Stress corrosion cracking (SCC) occurs through the combination of significant tensile stress, a corrosive environment, and a susceptible (sensitized) material. SCC can be categorized as either IGSCC, or TGSCC, depending upon the primary crack morphology. The minimum level of stress required for SCC is dependent not only on the material but also on temperature and environment. EPRI TR-103840, "BWR Containment License Renewal Industry report; Revision, and NUREG –0313, "Technical Report on Material Selection and Processing Guidelines For BWR Coolant Pressure Boundary Piping" consider operating temperature above 200° F as a limit of probable significant cracking of susceptible stainless steels.

The stainless steel sleeves are exposed to torus water and reactor building torus compartment sheltered environment. The torus water operating temperature is less than 95° F and the operating temperature range for the sheltered environment is 65° F - 80° F. These temperatures are significantly lower than the 200° F referenced above. Consequently, SCC is not identified as an aging effect for the thermowell sleeves.

Intergranular attack (IGA) cracking is initiated by mechanisms similar to SCC. However, the 95°F operating temperature is less than the temperature threshold where IGA can be expected.

RAI 3.3-6

In section 3.3.5, 3.3.6 and 3.3.14, internal surface of stainless steel, carbon steel and cast iron components are exposed to raw water environment. Typically, the aging effect, fouling, is associated with raw water environments. Explain why fouling is not identified as an applicable aging affect in pipe, pump casings, strainers, and valve bodies in a raw water environment. If it is identified, explain how this environment and the associated aging effect are managed in the LRA.

Response:

The aging effect of fouling, as it applies to pipe, pump casings, strainers and valve bodies, is called "flow blockage" in the PBAPS LRA. Flow blockage is identified as an applicable aging effect in pipe, pump casings, strainers, and valve bodies in a raw water environment. This aging effect is managed by the Generic Letter 89-13 Activity (LRA Appendix B.2.8). In addition, the Inservice Testing (IST) Program (LRA Appendix B.1.11) detects flow blockage in the Emergency Service Water (LRA Section 3.3.6) and Emergency Cooling Water (LRA Section 3.3.14) systems.

RAI 3.3-7

The following HVAC systems have been identified as being within the scope of license renewal:

Standby Gas Treatment System (section 2.3.2.7)
Control Room Ventilation System (section 2.3.3.8)
Battery and Emergency Switchgear Ventilation System (section 2.3.3.9)
Diesel Generator Building Ventilation System (section 2.3.3.10)
Pump Structure Ventilation System (section 2.3.3.11)

However, no aging effects were identified in Tables 3.2.7, 3.3.8, 3.3.9, 3.3.10, or 3.3.11 for the following component groups in sheltered or ventilation atmosphere environments:

Casting and Forging: Valve Bodies/ Pump Casings
Piping: Pipe, Tubing, Fittings
Piping Specialties: Flow Elements, Nitrogen Electric Vaporizer
Sheet Metal: Ducting, Damper Enclosures, Plenums, Fan Enclosures

Despite the statement in Section B.2.3 that "No physical degradation of metallic ventilation system components has been identified at PBAPS or by industry in general....", metallic HVAC system components at other nuclear power plant facilities have been identified as subject to aging effects. For example, the GALL Report, NUREG-1801 Chapter VII, Item F1-3 cites potential aging mechanisms for HVAC ducts as: Loss of material/General, pitting, crevice corrosion, and microbiologically influenced corrosion (for duct [drip-pan] and piping for moisture drainage). Please explain the basis for determining that no aging effects exist and no aging management activities are required for the systems identified above.

Response:

As stated in Section 3.0 of the LRA, the sheltered environment consists of indoor ambient conditions where components are protected from outdoor moisture. Conditions outside the drywell consist of normal room air temperatures ranging from 65°F - 150°F and a relative humidity ranging from 10% - 90%. The warmest room outside the drywell is the steam tunnel, with an average temperature of 150°F (based on measured temperatures), and maximum normal fluctuation to 165°F.

The drywell is inerted with nitrogen to render the containment atmosphere non-flammable by maintaining the oxygen content to less than 4% oxygen. The drywell normal operating temperature ranges from 65°F - 150°F with a relative humidity from 10% - 90%.

The sheltered environment atmosphere is an air or nitrogen environment with humidity. Components in systems with external surface temperatures the same or higher than ambient conditions are expected to be dry. Lack of a liquid moisture source in direct contact with a given component precludes the concern of external surface corrosion degradation of metallic components as an effect requiring aging management. The ventilation atmosphere environment is similar to the sheltered environment conditions. To guard against condensation, anti-sweat insulation was specified for piping and components where the process temperature is between 30°F and 60°F or is below ambient. Since the relevant conditions that contribute to the onset of loss of material are not present, there is no aging effect for metallic components that requires aging management in the sheltered and ventilation atmosphere environments during the period of extended operation.

Fire Protection

RAI 3.3-8

Table 3.3-7 identifies black steel pipe and carbon steel pipe used in raw water service in fire protection systems and an aging effect of flow blockage. The design basis of sprinkler systems requires an assumption of a roughness coefficient, a "C" factor in the Hazen-Williams equation. This coefficient declines with age, causing a greater pressure drop and subsequent reduced delivery of water to the suppression system. Changes in the value of this coefficient can be determined by flow tests and used to verify, by calculation, the ability of the system to perform its intended function in terms of flow rate and pressure. Inherent in sprinkler systems are pipe networks which cannot be flow tested. Over an extended time, the interior of the pipe can deteriorate through scaling and tuberculation until the system cannot deliver the required flow with the available pressure. This condition cannot be observed by external visual inspection. Appendix B.2-9 addresses flow testing and visual inspection to monitor and detect blockage. For the piping described above, flow testing is not reasonably achievable. Identify how the internal condition of this piping will be verified to assure flow capability.

Response:

In the PBAPS LRA, fouling of the pipe internals is addressed under the aging effect of Flow Blockage. Flow blockage of the wet pipe sprinkler system branch lines is managed by performance of periodic sprinkler system testing.

There are nineteen wet pipe sprinkler systems in the scope of license renewal at PBAPS. Alarm device tests are performed on all of these systems. The alarm device test can be performed by opening the alarm test valve or by opening the inspector's test valve, and then verifying proper actuation of the alarm pressure switch within the prescribed time. In addition, a main drain test is performed which verifies unobstructed flow to the wet pipe sprinkler system.

For all the wet pipe sprinkler systems, an alarm test is performed by opening the alarm test valve and verifying proper alarm actuation. An additional alarm test is performed on five of the wet pipe sprinkler systems by opening the inspector's test valve that is located at the most distant point in the sprinkler system from the alarm valve, and again verifying proper alarm actuation within the prescribed time. The inspector's test valve is opened to allow water to exit the system, resulting in observable flow and a reduction in sprinkler header pressure. Unobstructed flow from the test valve demonstrates that sprinkler heads and piping are not clogged from corrosion product debris. This test on five of the nineteen wet pipe sprinkler systems is considered a good representation for all nineteen lines since the environment, material and pipe sizes are similar.

This same concern was pursued by the NRC with the Hatch application in Hatch SER Open Item 3.1.18-1(a). According to the NRC closure of this Hatch Open Item in the Hatch SER, NUREG-1803, the NRC considers the wet pipe sprinkler system flow tests described by Hatch in their response to RAI 3.1.18-7 to be adequate for managing flow degradation.

The sprinkler system testing performed at PBAPS is similar to the testing described in the licensee response to Hatch RAI 3.1.18-7 and accepted by the NRC in NUREG-1803.

RAI 3.3-9

The aging effect of several materials referenced in Table 3.5-14 is listed as Change in Material Properties. Appendix B.2.9 states these changes in material properties will be monitored by visual inspection. Provide the acceptance criteria for required inspection which would identify unacceptable changes in material properties and the bases for these criteria.

Response:

Change in material properties aging effect is specified in Table 3.5-14 for materials, which are used for the following component groups:

1. Fire Barrier Penetration Seals
2. Other Hazard Barrier Penetration Seals
3. Gaskets for watertight doors
4. Fire Wraps
5. Expansion Joint Seals

1. Fire Barrier Penetration Seals. Specified quantities of fire barrier penetration seals are visually inspected as indicated in LRA Section B.2.9, "Fire Protection Activities". Each penetration seal, selected for inspection, is compared to its original installation detail drawing. Inspection and acceptance criteria are indicated on the drawings and depend on seal materials and seal configuration. Specific visual inspection and acceptance criteria for silicone type seals are:
    - Verify silicone seal is in place
    - Verify there are no voids greater than a depth of ¼" in the surface of the seal
    - Verify that shrinkage of seal away from items which penetrate the seal (cables, conduits, pipe, tubing, etc.) is less than 1/8" and no deeper than ¼"

- Verify that shrinkage of seal away from penetration surface (concrete or embedded sleeve) is less than 1/8" and no deeper than ¼".

Visual inspection and acceptance criteria for grout/cement type seals are:

- Verify grout seal is in place
- Verify shrinkage of the grout away from the penetrating items is less than 1/8" and no deeper than ½"
- Verify shrinkage of the grout away from the penetration surface is less than 1/8" and no deeper than ½".
- Verify there are no cracks wider that 1/8" in the surface of the seal.
- If an existing void or crack is greater than ½" deep, verify that the depth of sound grout is a least 8".

Similar inspection and acceptance criteria are specified for other fire barrier penetration seal types to ensure their fire protection intended function is maintained. It is relevant to note that PBAPS operating experience has not identified age related degradation of fire barrier penetration seals. Instead, the materials have proven to be age independent, consistent with NRC letter SECY-96-146, "Technical Assessment of Fire Barrier Penetration Seals in Nuclear Power Plants" findings.

2. Other Hazard Barrier Penetration Seals: These seals are monitored as a part of the specific hazard barrier (i.e. flood, HELB, etc.) performed in accordance with the PBAPS Maintenance Structural Monitoring Program (B.1.16). The seals are inspected for separation gaps, voids, tears or general degradation by qualified evaluator or inspector (See Response to RAI B.1.16-2). Inspection results are classified as "acceptable", "acceptable with deficiencies", or "unacceptable" based on whether the hazard barrier can perform its intended function considering the condition of the seal. Conditions that are classified "acceptable with deficiencies" and "unacceptable" are evaluated, documented and subject to corrective action.

3. Gaskets for watertight doors: Door inspection activities (B.2.6) require visual examination of watertight door gaskets for cracks, rips, tears, and other degradations that may cause loss of seal. Although these inspection criteria may not be a direct measurement of the gasket change in material properties, it is a good indicator of the gasket's physical condition and its ability to provide an adequate seal. Gaskets are repaired or replaced if upon examination their condition indicates loss of seal potential.

4. Fire Wraps: Fire wrap material is used for encapsulation of electrical raceways, for coating of steel beams, and cable tray covers.

Fire protection activities (B.2.9) require visual inspection of encapsulated electrical raceways for defects that include water damage, shrinkage of material, holes, punctures, gaps, cracks, and physical damage to the encapsulation surface. Inspection results are classified as satisfactory (no defects) or unsatisfactory. When encapsulation is determined to be unsatisfactory, compensatory actions per the PBAPS Technical Requirements Manual are established pending completion of the corrective action. Similar inspection and acceptance criteria are provided for fire wrap material used for coating of steel beams and cable tray covers.

5. Expansion Joint Seals. Same as item 2 above for other hazard barrier penetration seals.

RAI 3.3-10

Table 3.3.7 identifies sprinkler heads in four different locations and indicates aging effects as none in one case and three different aging effects in the other listing. It is unclear which heads have no aging effects. Identify by type and plant location which sprinkler heads are considered as having no aging effects. Provide the basis for the conclusion that there are no aging effects.

Response:

The applicable aging effects are a function of the material of construction and the environment. As indicated in LRA Table 3.3-7, brass and chrome plated brass sprinkler heads located in a raw water environment are subject to loss of material, cracking, and flow blockage aging effects. These aging effects are managed by the Fire Protection Activities (Section B.2.9).

LRA Table 3.3-7 also identifies bronze sprinkler heads located in a dry gas environment. The dry gas environment is considered inert with respect to corrosion potential because there is no significant moisture content. There are no aging effects applicable to bronze sprinkler heads in a dry gas environment.

LRA Table 3.3-7 indicates that the sprinkler heads in a raw water environment are subject to loss of material, cracking and flow blockage aging effects, while the sprinkler heads located in a dry gas environment have no aging effects.

RAI 3.3-11

In Table 3.3.7 on page 3-77 of the LRA, the applicant does not identify an aging effect for bronze valve bodies in an outdoor environment. The staff requests that the applicant provide information supporting the exclusion of aging effects, such as loss of material, for these components.

Response:

The aging management review determined that there are no aging effects for bronze in an outdoor environment. This determination was based on the evaluation in EPRI 1003056, "Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Rev. 3" that copper alloys are resistant to general corrosion in a gas environment, even in the presence of oxygen and moisture. This statement is also applicable to an outdoor environment, which would be similar to a wetted gas environment. The plant specific operating experience indicates that atmospheric conditions at PBAPS do not contain high levels of contaminants that would result in an aggressive corrosive environment. EPRI 1003056 also indicates that bronze is resistant to stress corrosion cracking. Based on the EPRI guidance and the plant specific operating experience, no aging effects are identified for bronze material on an outdoor environment.

3.4 Aging Management of Steam and Power Conversion Systems

RAI 3.4.1

Table 3.4-1 describes aging management review results for component groups in the Main Steam System. Provide definition of all aging effects and environments that are listed in Table 3.4-1. Describe the process that was used to identify the aging effect for each component listed in Table 3.4-1. Discuss how operating experiences impacted the process for identifying aging effects?

Response:

The aging effects terminology used in the License Renewal Application (LRA) is consistent with the terminology used in NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," and in NUREG-1801, "Generic Aging Lessons Learned (GALL) Report." The environments listed in Table 3.4-1 are defined in LRA Section 3.0, under the heading of "Environment."

Aging effects are identified as part of the aging management review, based on guidance contained in the above referenced documents including consideration of industry and plant specific operating experience. The LRA identifies the appropriate aging effects consistent with the guidance of NEI 95-10 Revision 3, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 – The License Renewal Rule," endorsed by NRC Regulatory Guide 1.188. Industry and plant specific operating experience is accounted for in the selection of aging effects identified in the Section 3 Tables. The review of industry and plant specific operating experience is documented in the aging management review reports. The aging management review (AMR) reports are prepared, reviewed and approved in accordance with controlled procedures and will be subject to NRC audit. The AMRs identify the applicable aging effects and the necessary aging management activities to manage the effects of aging for the period of extended operation.