3 AGING MANAGEMENT REVIEW RESULTS

3.0 Common Aging Management Programs

The applicant provided a proposed supplement to the Updated Final Safety Analysis Report (UFSAR Supplement) in Appendix A to the LRA, in accordance with 10 CFR 54.21(d). The purpose of the proposed UFSAR Supplement is to provide an appropriate description of the programs and activities for managing the effects of aging and the evaluation of time-limited aging analyses (TLAAs), so that any future changes to the programs or activities that may affect their effectiveness will be controlled under 10 CFR 50.59. A condition will be included in the renewed license requiring the applicant to include the UFSAR Supplement in the next UFSAR update, required by 10 CFR 50.71(e).

The applicant committed to performing future inspections before the extended period of operation. These commitments are identified in the UFSAR Supplement, submitted pursuant to 10 CFR 54.21(d), as part of the proposed aging management programs. Upon satisfactory completion of these activities prior to entering the extended period of operation (i.e., no later than August 8, 2013 for Unit 2 and June 13, 2018 for Unit 3), the staff can conclude that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB, as requested by 10 CFR 54.29. A condition will be included in the renewed license requiring completion of these inspection activities before the beginning of the period of the extended operation.

3.0.1 Introduction

This section of the SER contains the staff's evaluation of 22 AMPs that are in Appendix B of the LRA and are referenced as a part of the AMR for two or more of the systems and/or structures. It should be noted that the staff's conclusions on the evaluations of these 21 common AMPs may be predicated on the assumption that they are implemented in conjunction with other AMPs (if more than one AMP is credited by the applicant) as discussed in subsequent sections of this SER for managing the effects of aging of SCs that are subject to an AMR.

In addition in one case the applicant has indicated that the aging management program relied on is consistent with the Generic Aging Lessons Learned (GALL) report, NUREG-1801. The GALL report contains the staff's generic evaluation of the existing plant programs and documents the technical basis for determining where existing programs are adequate without modification and where existing programs should be augmented for the extended period of operation. The GALL report should be treated in the same manner as an approved topical report that is generically applicable. An applicant may reference the GALL report in a license renewal application to demonstrate that the programs at the applicant's facility correspond to those reviewed and approved in the GALL report and that no further staff review is required. If an applicant takes credit for the program in GALL, it is incumbent on the applicant to ensure that the plant program contains all the elements of the referenced GALL program. In addition, the conditions at the plant must be bounded by the conditions for which the GALL program was evaluated. The above verifications must be documented on-site in an audit able form.

3.0.2 Program and Activity Attributes

The staff's evaluation of the applicant's AMPs focuses on program elements, rather than the details of specific plant procedures. To determine whether the applicant's AMPs are adequate to manage the effects of aging so that the intended functions will be maintained consistent with the current licensing basis (CLB) for the period of extended operation, the staff used 10 elements to evaluate each program and activity. The 10 elements of an effective AMP were developed as part of NUREG 1800, "Standard Review Plan for License Renewal," which was issued in July 2001. This SER describes the extent to which the 10 elements, as described in Appendix A of NUREG-1800 (Branch Technical Position, A.1 Aging Management Review Generic), are applicable to a particular program or activity, and evaluates each program and activity against those elements. On the basis of NRC experience with maintenance programs and activities, the staff concluded that conformance with the 10 elements of an AMP, or a combination of AMPs, provides reasonable assurance that an AMP (or combination of programs and activities) is effective at managing an applicable aging effect. The following 10 elements of an effective AMP will be considered in evaluating each AMP used by the applicant to manage the applicable aging effects identified within this SER:

1. scope of program
2. preventive actions
3. parameters monitored or inspected
4. detection of aging effects
5. monitoring and trending
6. acceptance criteria
7. corrective actions
8. confirmation process
9. administrative controls
10. operating experience

The applicant did not initially describe how the elements involving corrective actions, confirmation process, and administrative controls for license renewal are implemented in Appendix B of the LRA. The staff's evaluation of the applicant's corrective action program, confirmation process and administrative controls was generic and is evaluated separately in Section 3.0.4 of this SER.

3.0.3 Common Aging Management Programs and Activities

3.0.3.1 Flow-Accelerated Corrosion Program

The applicant described the flow-accelerated corrosion (FAC) aging management program (AMP) in Section B1.1 of Appendix B of the LRA. The AMP is an existing aging management program. The program provides procedures to predict, detect, and monitor wall thinning in piping and fittings due to flow-accelerated corrosion. The applicant stated that the FAC program is based on the EPRI guidelines in NSAC-202L-R2, April 1999, “Recommendations for an Effective Flow-Accelerated Corrosion Program.” In addition, a Peach Bottom Atomic Power Station (PBAPS) specification ensures that the FAC program will be implemented as required by NRC Generic Letter 89-08, “Erosion/Corrosion-Induced Pipe Wall Thinning.”

3.0.3.1.1 Technical Information in the Application

In Section B1.1 of the LRA, the applicant described the procedures for the prediction of the amount of wall thinning in pipes and fittings through analytical evaluations and periodic examinations of locations most susceptible to FAC-induced loss of material. Specifically, the program includes analyses to determine critical locations, baseline inspections to determine the extent of thinning at these locations, and followup inspections to confirm the predictions. Repairs and replacements are performed as necessary. The susceptible piping systems are divided into two categories. Category 1 consists of piping systems, or portions of systems, that are susceptible to FAC and have a completed FAC Wear Rate Analysis in EPRI's CHECWORKS computer code. Category 2 consists of piping systems, or portions of systems, that are susceptible to FAC but do not have a completed FAC Wear Rate Analysis in the CHECWORKS computer code.

These piping components are in the engineered safety features systems (the high-pressure coolant injection and the reactor core isolation cooling systems) and the steam and power conversion systems (the main steam and the feedwater systems). The intended functions of these pipings, their associated environment, the materials of construction, and the aging effects are listed in Tables 3.2-1 and 3.2-4 and Tables 3.4-1 and 3.4-3 of the LRA.

3.0.3.1.2 Staff Evaluation

The staff reviewed the applicant's description of the AMP in the LRA to determine whether the applicant has demonstrated that the FAC AMP will adequately manage the applicable effects of aging due to flow-accelerated corrosion for susceptible piping systems during the period of extended operation as required by 10 CFR 54.21(a)(3).

The staff's evaluation of the FAC program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

Program Scope: The purpose of the FAC program is to supply procedures for prediction, inspection, and monitoring of piping and fittings for the loss of material due to FAC so that timely and appropriate action may be taken to minimize the probability of experiencing a FAC-induced consequential leak or rupture. The applicant further stated that the FAC program elements are based on the recommendations identified in NSAC-202L-R2, which requires controls to assure the structural integrity of carbon steel lines containing high-energy fluids (two phase as well as single phase). The PBAPS FAC program manages loss of material in carbon steel piping and fittings. The PBAPS feedwater system is classified as Category 1. The main steam system and the HPCI and RCIC steam line drains are classified as Category 2. The staff found the scope of the program to be acceptable because the applicant adequately addressed the systems and components whose aging effect could be managed by the application of this activity.

Preventive or Mitigative Actions: The applicant described the FAC program as a condition monitoring program that identifies loss of material aging effects prior to loss of intended function. The applicant stated that no preventive or mitigative attributes are associated with the FAC program. The staff found this program attribute acceptable because condition monitoring should identify degradation before there is a loss of intended function.

Parameters Monitored or Inspected: The applicant stated that piping and fitting wall thickness reduction could challenge the maintenance of the pressure boundary intended function. Therefore, the applicant performs inspections to monitor the wall thickness of piping and fittings susceptible to FAC-induced loss of material as provided in the FAC program procedures. The procedures of the parameters monitored and inspected are provided below in the discussion of the detection of aging effects and monitoring and trending attributes. The staff found this program attribute adequate because the parameter monitored, wall thickness, should detect the presence and extent of the aging effect. In addition, operating experience EPRI and NRC guidelines support the monitoring of wall thickness to mitigate FAC related and degradations.

Detection of Aging Effects: Periodic ultrasonic inspections are conducted of components susceptible to FAC to validate analytical evaluations. The extent and schedule of inspections ensure that loss of material (wall thinning) of piping and fittings is detected prior to loss of intended function of the piping. The staff requested additional information as to the applicant's approach in identifying the susceptible components and locations to manage FAC. The applicant responded, in a letter to the NRC, dated May 14, 2002, that the susceptible piping systems are divided into two categories: Category 1, which consists of piping systems, or portions of systems, that are susceptible to FAC and have a completed FAC Wear Rate Analysis in CHECWORKS (a computer code developed by EPRI), and Category 2, which consists of piping systems, or portions of systems, that are susceptible to FAC but do not have a completed FAC Wear Rate Analysis in CHECWORKS.

For Category 1 systems, susceptible locations and components are based on CHECWORKS Wear Rate ranking results for each piping system. To the extent practical, varying geometry types (elbows, reducers, tees, etc.) are selected. For Category 2 systems, locations are conservatively selected using a combination of engineering judgment, industry experience, and plant experience. Special consideration is given to such locations as nozzles and tees that are downstream of orifices or have complex geometry.

The applicant stated that components that are susceptible to FAC within the scope of its programs are documented in industry and regulatory reports, such as NRC Information notices, significant operating experience reports (SOERs), and EPRI reports. Plant operating experience is provided through results of previous ultrasonic testing examinations of the subject piping inspections.

The staff found this program attribute acceptable because the applicant's program as described in its LRA should identify the susceptible components and locations to manage FAC and the program activities may be relied upon to provide reasonable assurance that aging effects will be detected before there is a loss of intended function.

Monitoring and Trending: The FAC AMP supplies analytical evaluations using parameters such as pipe material, geometry, hydrodynamic conditions, temperature, pH, and oxygen content to predict wall thickness reduction due to FAC. Inspections of the piping verify the evaluations.

The schedule of the next inspection is based on the remaining life determined after each inspection. If degradation is detected such that the wall thickness is less than the minimum predicted thickness, additional examinations are performed in similar and adjacent areas to bound the thinning. The FAC program provides reasonable assurance that structural integrity will be maintained between inspections. The staff found the applicant’s approach to monitoring activities to be acceptable because it is based on methods that are sufficient to predict the extent of degradation so that timely corrective or mitigative actions are possible.

Acceptance Criteria: The applicant stated that inspection results are used to calculate the number of refueling or operating cycles remaining before the component reaches design code minimum allowable wall thickness. If calculations indicate that an area will reach design code minimum allowable thickness before the next scheduled outage, the component is repaired, replaced, or reevaluated. Based on the applicant’s approach, the staff concludes that the acceptance criteria should ensure that the intended functions are maintained for the period of extend operation for the components within the scope of program.

Operating Experience: The applicant’s FAC AMP is an existing program. The applicant stated that wall thinning problems in single-phase systems have occurred throughout the industry in feedwater and condensate systems and in two-phase piping in extraction steam lines and moisture separator reheater and feedwater heater drains. The PBAPS HPCI and RCIC steam drain lines have experienced wall thinning due to FAC and this piping has been replaced. The FAC program was originally outlined in NUREG-1344 and implemented through GL 89-08. The FAC program has evolved through industry experience and is now described in NSAC-202L. Application of the FAC program has resulted in the replacement of piping identified as being subject to FAC before loss of material has challenged pressure boundary integrity. The FAC program has provided an effective means of ensuring the structural integrity of high-energy carbon steel systems.

The NRC has audited industry programs based on the EPRI methodology at several plants and has determined that these activities can provide a good prediction of the onset of FAC so that timely corrective actions can be undertaken. The PBAPS FAC program is updated to reflect the latest industry and plant experience. The applicant stated that modifications have been implemented at PBAPS due to discovery of pipe wall thinning or leakage. The applicant further stated that no failures, other than in HPCI and RCIC steam drain lines, have occurred in any components at PBAPS within the scope of license renewal.

The staff requested additional information on whether the applicant has reviewed the operating experience as discussed in NRC IN 2001-09, “Main Feedwater System Degradation in Safety-Related ASME Code Class 2 Piping Inside the Containment of a Pressurized Water Reactor.” The extent of the degradation of the main feedwater piping at the time of discovery of the incident reported in NRC IN 2001-09 is of particular concern given the maturity of the industry's FAC program. Even though this reported incident occurred in to a PWR plant, numerous incidents of wall thinning due to erosion/corrosion have been reported for both PWR and BWR plants. The staff was not certain whether the applicant had considered the operating experience reported in NRC Information Notice 2001-09. The applicant responded, in a letter to the NRC dated May 14, 2002, that regulatory reports such as NRC information notices are routinely reviewed at PBAPS for applicability. Although NRC IN 2001-09 only applies to PWRs and therefore is not applicable to PBAPS, it will be reviewed at PBAPS to determine if any changes to the existing FAC program are required in regard to wall thinning due to erosion/corrosion.

The staff found that the aging management activities described above are based on plant and industry experience. Because the applicant was incorporating operating experience into their program, the staff concluded that the applicant had provided evidence that the effects of aging will be managed so that the structure and component intended functions will be maintained during the extend period of operation.

3.0.3.1.3 UFSAR Supplement

The staff reviewed Section A.1.1 of the UFSAR Supplement (Appendix A of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management associated with flow-accelerated corrosion is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

3.0.3.1.4 Conclusions

The staff concludes that the applicant has demonstrated that the aging effects associated with flow-accelerated corrosion will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities associated with flow accelerated corrosion for managing the effects of aging as required by 10 CFR 54.21(d).

3.0.3.2 Reactor Coolant System Chemistry Program

3.0.3.2.1 Technical Information in the Application

The applicant described its Reactor Coolant System (RCS) chemistry program AMP in Section A.1.2 of Appendix A and Section B.1.2 of Appendix B of the LRA. The RCS chemistry activities manage loss of material and cracking in reactor, RPV instrumentation, reactor recirculation, standby liquid control, feedwater, HPCI, RCIC, core spray, RHR, PCIS (RWCU), and main steam systems by monitoring and controlling detrimental contaminants.

The objective of the RCS chemistry program is to optimize the water chemistry so that aging effects, loss of material, and cracking will be minimized.

In Section 3.1 of the LRA, the applicant identified the following mechanical systems that contain the components that are affected by the RCS chemistry program:

- reactor pressure vessel and internals
- reactor pressure vessel instrumentation system
- reactor recirculation system

The details of these systems are described in Section 2.3.1 of the LRA and Sections 3.3, 4.2, 4.3, 7.8, and 7.9 of the Plant Peach Bottom UFSAR.

The control of reactor water chemistry is accomplished in accordance with EPRI TR-103515, "BWR Water Chemistry Guidelines," 2000 revision.

3.0.3.2.2 Staff Evaluation

The staff reviewed the information included in the relevant sections of the LRA regarding the applicant's demonstration of the RCS chemistry program to ensure that the effects of aging on components exposed to the reactor water chemistry will be adequately managed, so that the intended functions will be maintained consistent with the CLB for the period of extended operation for all components in the systems included in the scope of the program, in accordance with 10 CFR 54.21(a)(3).

The components exposed to the reactor water environment are made of carbon steel, low-alloy steel, austenitic stainless steel, and nickel-based alloys. The aging effects to be managed by the reactor water chemistry control program are loss of material and cracking. Loss of material is occurring mainly in low-alloy steel, carbon steel, and stainless steel. Cracking is occurring in austenitic stainless steels and nickel-based alloys. The applicant describes the RCS chemistry program as an existing program. The program manages loss of material and cracking of reactor coolant system components exposed to reactor coolant and steam. This program relies on monitoring and control of water chemistry to keep peak levels of various contaminants below the specific preestablished limits.

The staff's evaluation of the RCS chemistry program focused on how the program manages aging effects through effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, administrative controls, and operating experience are part of the site quality assurance program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

Program Scope: The RCS chemistry activities manage loss of material and cracking in reactor, RPV instrumentation, reactor recirculation, standby liquid control, feedwater, HPCI, RCIC, core spray, RHR, PCIS (RWCU), and main steam systems by monitoring and controlling detrimental contaminants. The components in the reactor coolant system that are exposed to the reactor water environment and require aging management by this program are identified in Section 3.1 of the LRA. According to EPRI TR-103515, the chemistry needs to be controlled in the reactor coolant system and other systems such as the condensate/feedwater cycle and the reactor water cleanup system. The staff finds the scope of the subject AMP adequate because it applies to the components that are exposed to the reactor coolant environment.

Preventive or Mitigative Actions: RCS chemistry activities include periodic monitoring and controlling of RCS water chemistry to ensure that known detrimental contaminants are maintained within preestablished limits, providing reasonable assurance that the aging effects of loss of material or cracking will be managed. According to EPRI TR-103515, the chemistry needs to be controlled in the reactor coolant system and other systems such as the condensate/feedwater cycle and the reactor water cleanup system. The staff agrees that periodic monitoring of RCS chemistry based on EPRI TR-103515 should mitigate degradation.

Parameters Monitored or Inspected: The subject program continuously monitors coolant conductivity and measures the impurities such as chlorides and sulfates when the conductivity measurements indicate abnormal conditions. An earlier version of EPRI TR-103515, however, requires that the sulfates and chlorides be measured daily. The applicant's reactor water chemistry control program is based on the guidance presented in EPRI TR-103515, "BWR Water Chemistry Guidelines" 2000 revision. The staff has not approved the EPRI TR-103515 2000 revision for generic use. The staff reviewed the 1996 revision of EPRI TR-103515 in a September 18, 1998, letter from D.S. Hood, NRC, to J.H. Mueller, Niagara Mohawk Power Corporation. In RAI 3.1-13(a), the applicant was requested to identify the differences between the 1996 Revision and the 2000 Revision of EPRI TR-103515, so that the staff can determine the effectiveness of the parameters being monitored by this AMP. In response, the applicant identified the following differences:

(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 three 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 hydrogen water chemistry (HWC) or HWC with noble metals chemical addition (NMCA) no longer need to measure electrochemical potential (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 chlorides and sulfates. 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. PBAPS has implemented this change.

The staff finds the provisions of the 2000 revision of EPRI TR-103515 acceptable because the program is based on updated industry experience.

In RAI 3.1-13, the staff further requested information about whether the 2000 version requires continuous monitoring of dissolved oxygen concentration in the reactor feedwater/condensate system and control rod drive water system. In response, the applicant stated that 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.

In RAI 3.1-13, the staff also requested information about whether normal or HWC with NMAC is applied at the Peach Bottom plants and about the parameters monitored to assess the effectiveness of this water chemistry. In response, the applicant stated that 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. The applicant provided tables of parameters and frequencies for monitoring the effectiveness of the NMCA/HWC water chemistry and EPRI BWR Water Chemistry Guidelines limits, including administrative limits which are in accordance with the 2000 revision of the EPRI BWR Water Chemistry Guidelines.

The applicant also stated that PBAPS 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 ECP and the 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 it must use secondary measurements (reactor water dissolved oxygen and HWC hydrogen flow/feedwater flow).

The staff finds acceptable the applicant's response about the use of continuous monitoring of dissolved oxygen and the use of hydrogen water chemistry with NMAC at PBAPS, as well as the parameters monitored to assess the effectiveness of this water chemistry because they are in accordance with industry guidelines and provide an effective method of monitoring the water chemistry .

Detection of Aging Effects: The applicant stated that the subject program mitigates the onset and propagation of loss of material and cracking and no credit is taken for detection of aging effects in the affected components. The staff concurs with the applicant’s statement.

Monitoring and Trending: The subject program does not monitor or trend age-related component degradation. However, the EPRI BWR Water Chemistry Guidelines (EPRI TR-103515) include guidelines for data collection and trending methodologies for evaluation of reactor water chemistry control parameters. The conductivity is monitored continuously and the chloride and sulfate concentrations are monitored daily. The dissolved oxygen concentration is also monitored continuously. In response to the staff RAI 3.1-13, the applicant submitted information about monitoring of these parameters; the information is presented in this section of the SER in the evaluation of parameters monitored or inspected. The staff finds this response acceptable because the frequency allows timely detection of off-chemistry conditions. In addition, the staff requested that the applicant provide periodic inspections to confirm the effectiveness of the RCS Chemistry program for carbon steel components. This is part of Open Item 3.0.3.6.2-1 (see Section 3.0.3.6 of this SER).

Acceptance Criteria: The applicant states that the acceptance criteria for the reactor water chemistry control parameters are based on the EPRI BWR Water Chemistry Guidelines. These guidelines specify the minimum reactor water control parameters (conductivity < 0.30 mS/cm, chlorides < 5 parts per billion (ppb) and sulfates < 5 ppb) during normal power operation. When a parameter has exceeded the guidelines, specify the adequate action level that the plant operator enter. These guidelines also provide the minimum dissolved oxygen concentration (<200 ppb in reactor feedwater/condensate and control rod drive water) for action level during normal power operation. These criteria are acceptable because they are in accordance with industry guidelines that have been proven successful.

Operating Experience: The major aging-related degradation found at Plant Peach Bottom is cracking of stainless steel recirculation and residual heat removal (RHR) system piping caused by IGSCC. Loss of material was found in the high-pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) system carbon steel steam line drains. Portions of the "304 stainless" steel recirculation system were replaced with more IGSCC-resistant, low-carbon, "316 stainless" steel piping. The HPCI and RCIC steam drain lines were also replaced.

In RAI 3.1-13(b), the staff requested information about the effectiveness of the EPRI BWR Water Chemistry Guidelines (TR-103515). In response, the applicant stated that the RCS water chemistry is maintained in accordance with 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.

The staff finds that the plant-specific and industry-wide operating experience confirm the effectiveness of the RCS chemistry program.

3.0.3.2.3 UFSAR Supplement

The staff reviewed Section A.1.2 of the UFSAR Supplement (Appendix A of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

3.0.3.2.4 Conclusions

The staff concludes that the applicant has demonstrated that the aging effects associated with reactor coolant system chemistry will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.0.3.3 Closed Cooling Water Chemistry

The applicant described the closed cooling water chemistry AMP in Section B1.3 of Appendix B of the LRA. This is an existing aging management program. The program provides procedures to monitor periodically and maintain the closed cooling water quality in accordance with the guidelines of EPRI TR-107396, "Closed Cooling Water Chemistry Guidelines." The staff reviewed the applicant's description of the AMP in the LRA to determine whether the applicant has demonstrated that the closed cooling water chemistry AMP will adequately manage the applicable effects for components in the primary containment isolation (PCI) and the emergency diesel generator (EDG) systems during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.0.3.3.1 Technical Information in the Application

In Section B1.3 of the LRA the applicant stated that the closed cooling water chemistry AMP manages loss of material in carbon steel, aluminum, brass, bronze, and cast iron components and cracking of stainless steel components exposed to closed cooling water in the PCI and the EDG systems. In addition, the closed cooling water chemistry AMP also manage heat transfer reduction for the EDG heat exchanger components. These components in the PCI and EDG systems, their intended functions, the associated environment, the materials of construction, and the aging effect are described in Sections 3.2 and 3.3 of the LRA.

The program provides procedures to monitor periodically and maintain the closed cooling water quality in accordance with the guidelines of EPRI TR-107396, "Closed Cooling Water Chemistry Guidelines." The quality of the closed cooling water is maintained by monitoring and controlling detrimental contaminants and maintaining corrosion inhibitors.

3.0.3.3.2 Staff Evaluation

The staff reviewed the applicant's description of the AMP in the LRA to determine whether the applicant has demonstrated that the closed cooling water chemistry AMP will adequately manage the applicable effects for components in the primary containment isolation (PCI) and the emergency diesel generator (EDG) systems during the period of extended operation as required by 10 CFR 54.21(a)(3).

The staff's evaluation of the closed cooling water chemistry program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicates that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

Program Scope: The CCW chemistry AMP manages loss of material and cracking in systems and portions of systems within the emergency diesel generator and primary containment isolation systems subject to a closed cooling water environment by monitoring and controlling detrimental contaminants and maintaining corrosion inhibitors to minimize corrosion. CCW chemistry activities also manage heat transfer reduction for the EDG air coolant coolers and the EDG jacket coolant coolers. The staff found the scope of the program to be acceptable because the applicant adequately addressed the components whose aging effects could be managed by the application of this activity.

Preventive or Mitigative Actions: The CCW chemistry AMP includes periodic monitoring and controlling of corrosion inhibitor concentrations within the specified limits of EPRI TR-107396 to minimize corrosion and protect metal surfaces. The applicant also maintains the system corrosion inhibitor concentration within the preestablished limits, which provides reasonable assurance that the aging effects of loss of material, cracking, and heat transfer reduction will be managed. The staff finds these actions, based on EPRI guidelines, to be acceptable for preventing or mitigating the aging effects of loss of material, cracking, and heat transfer reduction.

Parameters Monitored or Inspected: The applicant identified the chemistry control parameters to be monitored per the recommendations of EPRI TR-107396. These include nitrite, pH, and methylbenzyl triazole (TTA) levels. Chlorides, sulfates, nitrates, turbidity, and metals are monitored on a regular basis as diagnostic parameters to provide indication of abnormal conditions. If parameter limits are exceeded, the chemistry control procedures require that corrective action be taken to restore parameters to within the acceptable range. Maintenance of corrosion inhibitor levels within EPRI TR-107396 guidelines mitigates loss of material, cracking, and heat transfer reduction. The staff found these parameters acceptable because operating experience and the EPRI guidelines support the monitoring and control of these parameters to mitigate loss of material, cracking, and heat transfer reduction.

Detection of Aging Effects: The applicant stated that the CCW chemistry AMP mitigates aging effects rather than detects aging effects. The staff found this acceptable and agrees that this AMP does not have aging detection capability and that its use is to maintain an environment that will minimize aging effects such as loss of material, cracking, and heat transfer reduction.

Monitoring and Trending: The CCW chemistry is monitored to ensure corrosion inhibitors are being maintained within acceptable limits in accordance with EPRI guidelines. Samples are taken and analyzed, and the data are trended. The frequency of sampling is based on EPRI TR-107396. The staff requested additional information on whether increased frequencies are included in the station procedures since Section 5, "Performance Monitoring," of EPRI TR-107396 recommends that the sampling frequency on the CCW chemistry should be increased if aging effects are detected or suspected.

The applicant responded, in a letter to the NRC dated May 14, 2002, stating that when the parameters that are monitored exceed the expected values, chemistry supervision is notified, the situation is evaluated, and adequate corrective actions are implemented. The applicant further stated that these actions are determined by chemistry supervision on a case-by-case basis and may include reanalysis, chemical additions, system adjustments, or increased sampling frequency, and that increased sampling frequency is not always indicated, nor does it correct the abnormal condition. The staff found the applicant’s approach to monitoring activities to be acceptable because it is based on methods that are sufficient to predict the maintenance of CCW chemistry so that timely corrective or mitigative actions are possible. However, as discussed as part of **Open Item 3.0.3.6.2-1**, the staff requested that the applicant verify the effectiveness of the chemistry program through an inspection activity.

Acceptance Criteria: The applicant stated that levels for concentration of nitrite and TTA are maintained within the limits specified in EPRI TR-107396, “Closed Cooling Water Chemistry Guidelines.” Parameters maintained in the CCW systems include pH (8.5-10.5), nitrite (500-1100 ppm), and TTA (5-30 ppm). The staff requested additional information on the acceptance criteria, as indicated in Section A1.2.3.6 of NUREG-1800 (July 2001) for chlorides, sulfates, nitrate, turbidity, and metals which are monitored on a regular basis as diagnostic parameters to provide indication of abnormal conditions.

In the May 14, 2002, response, the applicant also stated that the PBAPS closed cooling water chemistry activities are based on EPRI TR-107396. The EPRI guidelines define control parameters as those that assist with maintaining system chemistry control and define diagnostic parameters as those that assist with corrective actions if improvement in system control is required. As diagnostic parameters, the chlorides, fluorides, sulfates, nitrates, turbidity, and metals are trended. On August 6, 2002, via teleconference the staff requested additional information regarding the chloride and fluoride acceptance criteria. The applicant responded during the call that the acceptance criterion parameters for the chlorides and fluorides is < 10 ppm. The staff requests that the applicant confirm this information in writing. **This is Confirmatory Item 3.0.3.3.2-1**.

If the sample analysis indicates a change, chemistry supervision is notified, the situation is evaluated, and adequate corrective actions are implemented. The staff found the acceptance criteria to be acceptable because the information in the application and the applicant’s responses to the staff are based on EPRI guidelines for closed cooling water chemistry.

Operating Experience: The CCW chemistry AMP is an existing program. The applicant stated that industry operating experience demonstrates that the use of corrosion inhibitors in closed cooling water systems that are monitored and maintained by CCW chemistry activities is effective in mitigating loss of material, cracking, and heat transfer reduction. No age-related failures have occurred in the components within the scope of license renewal that are covered by the PBAPS CCW chemistry AMP.

Section A1.2.3.10 of NUREG-1800 indicates that the information provided by the operating experience of an AMP may indicate when an existing program has succeeded and when it has failed in intercepting aging degradation in a timely manner. An existing AMP is effective if the operating experience of the AMP (including corrective actions, if necessary) demonstrates that aging degradation has been found in a timely manner prior to the actual loss of the component intended function. Therefore, the staff requested additional information on any operating experience related to component age degradation due to cracking and loss of material, or heat transfer reduction due to corrosion, occurring prior to age-related failures of the intended functions of the component. In addition, the staff requested the applicant to address the corrective actions performed prior to age-related failures. The applicant responded, in a letter to the NRC dated May 14, 2002, stating that the AMR of the operating experience did not identify any age-related degradation that required corrective action in the closed cooling water environment. The staff found that the aging management activities described above are based on plant and industry experience. The staff agreed that these activities are effective at maintaining the intended functions of the systems, structures, and components that may be affected by closed cooling water chemistry, and can reasonably be expected to do so for the period of extended operation.

3.0.3.3.3 UFSAR Supplement

The staff reviewed Section A.1.3 of the UFSAR Supplement (Appendix A of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

3.0.3.3.4 Conclusions

The staff concludes that with the exception of **Confirmatory Item 3.0.3.3.2-1**, that the applicant has demonstrated that the aging effects associated with closed cooling water chemistry will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.0.3.4 Demineralized Water and Condensate Storage Tank Chemistry Activities

Based on discussions with the staff during the RAI reviews, Exelon decided to modify the LRA Appendix B1.4 Condensate Storage Tank Chemistry Activities to include the demineralized water system supply to the standby liquid control system storage tank. The modified AMP includes water chemistry controls applied to the demineralized water system.

In a letter dated May 14, 2002, the applicant described the demineralized water and condensate storage tank (CST) chemistry activities AMP in the revised Section B1.4 of Appendix B of the LRA. These chemistry activities provide for monitoring and controlling of the CST and demineralized water chemistry using PBAPS procedures and processes based on EPRI TR-103515, “BWR Water Chemistry Guidelines.” The staff reviewed the applicant’s description of the modified AMP to determine whether the applicant has demonstrated that the demineralized water and CST chemistry activities AMP will adequately manage the applicable effects of aging caused by components exposed to demineralized water or CST water during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.0.3.4.1 Technical Information in the Application

The applicant credits the demineralized water and CST chemistry activities to manage loss of material of carbon steel and stainless steel components and cracking of stainless steel components exposed to CST water or demineralized water in the HPCI, core spray, RCIC, CRD, standby liquid control, demineralized water, and condensate storage system. In addition, the applicant also uses this AMP to manage loss of material, cracking, and heat transfer reduction of carbon steel and stainless steel components of the HPCI gland seal condenser and the RCIC and HPCI turbine lubricating oil cooler together with the PBAPS heat exchanger inspection AMP. The CST water is condensed nuclear boiler steam that has been filtered and demineralized. The water quality of demineralized water and CST water is monitored periodically and maintained in accordance with station procedures that include recommendations from EPRI TR-103515, “BWR Water Chemistry Guidelines.”

3.0.3.4.2 Staff Evaluation

The staff’s evaluation of the demineralized water and CST chemistry activities focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicates that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff’s evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

Program Scope: The applicant stated that the demineralized water and CST chemistry activities AMP manages loss of material and cracking of components exposed to CST water or demineralized water in the HPCI, RCIC, CRD, core spray, standby liquid control, demineralized water, and condensate storage systems. The CST chemistry activities also manage cracking, loss of material, and heat transfer reduction of the HPCI gland seal condenser and the RCIC and HPCI turbine lubricating oil cooler. The aging effects are managed by monitoring and controlling detrimental contamination in demineralized water and CST water using PBAPS procedures and processes based on EPRI TR-103515, “BWR Water Chemistry Guidelines” (the 2000 version). The staff found the scope of the program to be acceptable because it includes a comprehensive list of systems and components exposed to demineralized water or CST water environment.

Preventive or Mitigative Actions: The applicant described that the demineralized water and CST chemistry activities AMP includes periodic monitoring and controlling of demineralized water and CST water chemistry to maintain contaminants within preestablished limits specified in EPRI TR-103515. The staff found that these procedures are adequate because they include all of the activities needed to mitigate age-related effects that are within the scope of license renewal and provide reasonable assurance that the aging effects of loss of material, cracking, and heat transfer reduction will be managed.

Parameters Monitored or Inspected: The applicant identified the parameters to be monitored as conductivity, chlorides, and sulfates. The staff found these parameters acceptable because operating experience and the EPRI guidelines support the monitoring and control of these parameters to mitigate corrosion-related degradations and to ensure contaminants are not present in the demineralized water and CST water.

Detection of Aging Effects: The applicant indicated that the demineralized water and CST chemistry activities AMP mitigate the onset and propagation of loss of material, cracking, and heat transfer reduction; however, detection of aging effects is not credited. The staff believes that there should be a one-time inspection program to verify the effectiveness of the demineralized water and CST water chemistry control to manage loss of material of carbon steel components exposed to CST water or demineralized water. Therefore, in RAI B1.4-1, the staff requested the applicant to clarify whether there is a one-time inspection included in this AMP. The applicant was requested to include a one-time inspection or explain the basis for not including a one-time inspection.

In a letter dated May 14, 2002, the applicant stated that PBAPS has operating experience that verifies the effectiveness of these chemistry activities. Piping inspections are routinely performed in the Inservice Inspection (ISI) and FAC programs and have been satisfactory. Much of this piping exposed to CST water or demineralized water is ASME Section XI Class 2 piping, which requires periodic inspections of welds and pressure tests to verify integrity. In addition, the FAC program provides for inspections at several susceptible locations to verify required wall thickness. The applicant stated that the demineralized water and CST chemistry activities are sufficient to adequately manage aging effects of the systems and components exposed to CST water or demineralized water. The routine inspections performed for piping in the condensate storage water environment verify the effectiveness of the program. The staff found the applicant's response acceptable because it is doing periodic inspection of the piping. The staff also agreed that this AMP does not have aging detection capability and that the AMP is designed to maintain and demineralized water and CST water chemistry environment that will minimize aging effects such as loss of material and cracking.

Monitoring and Trending: The applicant stated that periodic sampling measurements are taken and analyzed, and the data are trended. The minimum frequency of sampling is once per week based on EPRI TR-103515. The staff found the weekly sampling adequate in providing data for trending and that the AMP would provide early indication of chemistry deviations, allowing for timely corrective action. However, as discussed as part of **Open Item 3.0.3.6.2-1**, the staff requested that the applicant verify the effectiveness of the chemistry program through an inspection activity.

Acceptance Criteria: The specific limits of demineralized water and CST water chemistry are conductivity (< 1 uS/cm), chloride (< 10 ppb), and sulfate (< 10 ppb). The minimum sampling frequency is once a week. These parameters and their maximum levels, and minimum frequency of measurement are based on the values specified in EPRI TR-103515. The staff found these values acceptable because they are consistent with the EPRI guideline which has been developed based on operating experience and has been effective over time with widespread use.

Operating Experience: The applicant stated that components within the scope of license renewal have not experienced any loss of function such as failure of pressure boundary due to exposure to demineralized water or CST water. The aging management review of operating experience did not identify any age-related degradation that required corrective action in a demineralized water or CST environment. The staff found that the applicant demonstrated that the demineralized water and CST water chemistry activities program has been effective in managing the aging effects associated with the systems and components exposed to demineralized water or CST water.

3.0.3.4.3 UFSAR Supplement

The staff reviewed Section A.1.4 of the UFSAR Supplement (Appendix A of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

3.0.3.4.4 Conclusions

The staff concludes that the applicant has demonstrated that the aging effects associated with demineralized water and condensate storage tank chemistry will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.0.3.5 Torus Water Chemistry Activities

The applicant described the torus water chemistry activities AMP in Section B1.5 of Appendix B of the LRA. The staff reviewed the applicant's description of the AMP in the LRA to determine whether the applicant has demonstrated that the torus water chemistry activities AMP will adequately manage the applicable effects of aging caused by components exposed to torus water during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.0.3.5.1 Technical Information in the Application

In Section B1.5 of the LRA, the applicant identified the torus water chemistry activities AMP as an existing aging management program. The applicant credits the torus water chemistry activities AMP with managing loss of material of carbon steel and stainless steel components and cracking of stainless steel components exposed to torus water in the high-pressure coolant injection (HPCI), core spray, reactor core isolation cooling (RCIC), residual heat removal (RHR), and main steam systems. In addition, the applicant credits the AMP to manage heat transfer reduction of carbon steel and stainless steel RHR heat exchanger components and cracking of stainless steel component supports submerged in torus water.

The torus-grade water quality is monitored periodically and maintained in accordance with station procedures that include recommendations from EPRI TR-103515, "BWR Water Chemistry Guidelines." Purity of the torus water is maintained by pumping the torus water through filters and demineralizers.

Some systems, located in the torus, pass through the surfaces of the torus water and are exposed to a water-gas interface. For some lines, the water-gas interface occurs at both inside and outside diameters of the pipe. The torus water chemistry activities AMP and the torus piping inspection AMP (a new one-time inspection AMP, as described in Section B.3.1 of the LRA), together, manage loss of material at water-gas interface of carbon steel torus piping.

The HPCI has a primary water source from the condensate storage tank, which has demineralized water, with a backup supply of torus water available from the suppression pool. The RCIC system could have a water source from either the condensate storage tank or the pressure suppression pool. Therefore, these components could be exposed to either torus water or demineralized water or both.

Most of the components' aging effects are managed by the torus water chemistry activities AMP alone, which is a preventive/mitigative aging management program. In some cases the components' aging effects are managed by the torus water chemistry activities AMP and other AMPs such as the torus piping inspection AMP, mentioned above.

Loss of material of carbon steel and stainless steel components in the HPCI, RCIC, core spray, RHR, and main steam systems is managed by the torus water chemistry activities AMP only. Cracking of stainless steel components in the HPCI and core spray systems and cracking of submerged stainless steel structural supports are also managed by the torus water chemistry activities AMP.

Loss of material of carbon steel heat exchanger components and the heat transfer reduction of carbon steel and stainless steel heat exchanger components of the RHR system are managed by the torus water chemistry activities AMP, the ISI AMP, and the GL 89-13 AMP.

Cracking of carbon steel and stainless steel heat exchanger components of the RHR system is managed by the torus water chemistry activities AMP and the GL 89-13 AMP.

3.0.3.5.2 Staff Evaluation

The staff's evaluation of the torus water chemistry activities focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicates that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

Program Scope: The applicant stated that the torus water chemistry activities AMP manages loss of material and cracking of components exposed to torus-grade water in the RHR, HPCI, RCIC, core spray and main steam systems. The torus water chemistry activities AMP also manages cracking of stainless steel component supports submerged in torus water and heat transfer reduction in the RHR heat exchangers. The aging effects are managed by monitoring and controlling detrimental contamination in the torus-grade water using PBAPS procedures and processes based on EPRI TR-103515, "BWR Water Chemistry Guidelines" (the 2000 version). The staff found the scope of the program to be acceptable because it includes a comprehensive list of systems, structures, commodities, and major components exposed to a torus water environment.

Preventive or Mitigative Actions: The applicant described that the torus water chemistry program includes periodic monitoring and controlling of torus-grade water chemistry to maintain the contaminants within preestablished limits specified in EPRI TR-103515. The staff found that these procedures are adequate to monitor and control the aging effects because they include all of the activities needed to mitigate age-related effects that are within the scope of license renewal.

Parameters Monitored or Inspected: The applicant identified the parameters to be monitored as conductivity, chlorides, and sulfates, total organic carbon, and turbidity. The staff found these parameters acceptable because operating experience and the EPRI guidelines support the monitoring and control of these parameters to mitigate corrosion-related degradations and to ensure contaminants are not present in the torus water.

Detection of Aging Effects: The applicant stated that the torus water chemistry activities AMP mitigates the onset and propagation of loss of material and heat transfer reduction; however, detection of aging effects is not credited. The staff believes that there should be a one-time inspection to verify the effectiveness of the torus water chemistry control. Therefore, in RAI B1.5-2, the staff requested the applicant to clarify whether there is a one-time inspection included in this AMP. The applicant was requested to include a one-time inspection or explain the basis for not including a one-time inspection.

In a letter dated May 14, 2002, the applicant stated that the PBAPS has operating experience that verifies the effectiveness of the torus water chemistry activities. Piping inspections are routinely performed on these systems in the ISI and FAC programs and have been satisfactory. Most of the piping exposed to torus water is ASME Section XI Class 2 piping, which requires periodic inspections of welds and pressure tests to verify integrity. In addition, the FAC program provides for inspections of several susceptible locations of these systems to verify required wall thickness. The applicant found that the torus water chemistry activities are sufficient to adequately manage aging and that the routine inspections performed on the piping in the torus-grade water environment verify the effectiveness of the program. The staff found the applicant’s response acceptable and agreed that this AMP does not have aging detection capability and that its function is to maintain a torus water chemistry environment that will minimize aging effects such as loss of material and cracking.

Monitoring and Trending: For the torus water chemistry activities AMP, the applicant indicated that periodic sampling measurements are taken and analyzed, and the data are trended. The frequency of sampling is based on EPRI TR-103515, which recommends sampling at least once every quarter. EPRI TR-103515 recommends increased frequencies if chemical ingress is detected or suspected. The staff found the frequency of sampling to be adequate in providing data for trending because it is based on an industry standard for early detection of chemistry deviations, allowing for timely corrective action. However, as discussed, as part of **Open Item 3.0.3.6.2-1**, the staff requested that the applicant verify the effectiveness of the chemistry program through an inspection activity.

Acceptance Criteria: The applicant stated that the specific limits of the torus water chemistry activities AMP are conductivity (< 5 µmho/cm), chlorides (< 200 ppb), sulfates (< 200 ppb), total organic carbon (< 1000 ppb) and turbidity (2-25 ntu). The minimum sampling frequency is quarterly. These parameters and their maximum levels and frequency of measurement are based on the values specified in EPRI TR-103515 for torus/pressure suppression pool. The staff found the applicant’s acceptance criteria acceptable because they are consistent with the EPRI guideline which was developed based on operating experience and has been effective over time with widespread use.

The staff also noted that the system description of the HPCI in the UFSAR of the LRA indicates that the HPCI has a primary water source from the condensate storage tank, which has demineralized water with a backup supply of torus water available from the suppression pool. The UFSAR also indicates that RCIC could have a water source from either the condensate water tank or the pressure suppression pool. Therefore, the components of HPCI or RCIC may be exposed to either torus water or demineralized water, or both.

The staff noted that the chemistry parameters and sampling frequency are quite different in the torus water chemistry AMP and the CST water chemistry AMP. The specific limits of the demineralized water chemistry are conductivity (< 1.0 µmho/cm), chlorides (< 20 ppb), sulfates (< 20 ppb), total organic carbon (< 200 ppb). Daily measurements of conductivity, chlorides, and sulfates are recommended for demineralized water in EPRI TR-103515. Therefore, in RAI B1.5-5, the staff requested the applicant to clarify which of these two AMPs is credited for these systems and provide the supporting justification.

In a letter dated May 14, 2002, the applicant stated that the HPCI and RCIC systems are normally lined up to have their water supply from the CST. In this configuration, most of the piping and components are in the CST water environment. The torus suction component groups and the piping that is inside the torus are always in the torus water environment. This is reflected in Table 3.2.1 of the LRA for HPCI and Table 3.2.4 of the LRA for RCIC.

The aging management review credited the torus water chemistry and CST water chemistry AMPs for the portions of the HPCI and RCIC system component groups that are in the respective environment. The only time that the torus water enters the piping that is normally exposed to the CST water is during a quarterly surveillance test which swaps the suction flow path to the torus for a brief time. After this flow path is proven, the piping is then flushed with CST water to reestablish the normal CST water environment. Also, there is an operating procedure that directs the piping to be flushed with CST water after any operation of the system that used the torus as the water source. The staff found the applicant's response comprehensive and satisfactory. The staff agreed that the aging management review credited the torus water chemistry and CST water chemistry AMPs for the portions of the HPCI and RCIC system component groups that are in the respective environment. The staff found the acceptance criteria acceptable because they are consistent with the EPRI guideline, which has been developed based on operating experience and has proven effective over time with widespread use.

Operating Experience: The torus water chemistry activities AMP is an existing program. The applicant stated that components within the scope of license renewal have not experienced any loss of function such as failure of pressure boundary or structural support due to exposure to torus water. In Appendix A of the LRA, the applicant stated that large-capacity passive pump suction strainers have been installed on each RHR suction line and other lines in the suppression pool, via plant modification, in response to NRC I.E. Bulletin 96-03, ‘‘Potential Plugging of Emergency Core Cooling Suction Strainers by Debris in Boiling Water Reactors.”

Because the amount of debris in strainers affects to the quality of the torus water, the staff requested the applicant to address the operating experience of the strainers as well as debris in the torus water in RAI B.1.5-7. In a letter dated May 14, 2002, the applicant stated that the operating experience of the strainers has been excellent. The differential pressure across the strainers is measured quarterly during the operability surveillance test. The data have been satisfactory since the strainers were installed. The inspection for debris in the Unit 3 torus in September 2001 found no measurable buildup of silt or sludge. Based on the applicant's response, the staff found that the torus water chemistry activities have been effective in managing the aging effects and are adequate to detect the aging degradation in a timely manner prior to loss of component intended function.

3.0.3.5.3 UFSAR Supplement

The staff reviewed Section A.1.5 of the UFSAR Supplement (Appendix A of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

3.0.3.5.4 Conclusions

The staff concludes that the applicant has demonstrated that the aging effects associated with torus water chemistry will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.0.3.6 Inservice Inspection Program

The applicant described the Inservice Inspection (ISI) program in Section B.1.8 of the LRA. The applicant credits this inspection program with managing aging effects of the ASME Class 1, 2, and 3 pressure-retaining components and support members exposed to various environments, including reactor coolant, torus water, borated water, raw water, steam, wetted gas, sheltered, and outdoor. The staff reviewed the applicant's description of the AMP in the LRA to determine whether the applicant has demonstrated that the ISI AMP will adequately manage the applicable effects of aging of the pressure-retaining components and support members exposed to various environments during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.0.3.6.1 Technical Information in the Application

Section B.1.8 of the LRA identifies the ISI AMP as an existing program that will be used by the applicant to manage aging effects of the ASME Class 1, 2, and 3 pressure-retaining components and support members exposed to reactor coolant, torus water, borated water, raw water, steam, wetted gas, sheltered (containment indoor condition), and outdoor conditions. The aging effects include loss of material of carbon steel and stainless steel components, cracking of stainless steel components, and loss of fracture toughness of cast stainless steel components. The program complies with the requirements of the 1989 edition of the ASME Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," and is augmented to address GL 88-01, "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping." In addition, the AMP provides condition inspection for piping and equipment supports in accordance with ASME Code Case N-491-1. The AMP provides aging management for a wide range of systems and components either by itself or with other AMPs. Specifically, the ISI AMP provides aging management of the followup systems:

A. Reactor Pressure Vessel Instrumentation System and Reactor Recirculation System

1. Cracking of low-alloy steel reactor pressure vessel closure studs exposed to sheltered environment and reactor coolant (ISI AMP alone)
2. Loss of material and cracking of the reactor pressure vessel instrumentation system Class 1 components exposed to reactor coolant or steam (with the RCS chemistry AMP)
3. Loss of material and cracking of the reactor recirculation system Class 1 components exposed to reactor coolant (with the RCS chemistry AMP)

B. Engineered Safety Feature Systems

1. Loss of material and cracking of the high-pressure coolant injection (HPCI), core spray (CS), primary containment isolation system (PCIS), reactor core isolation cooling (RCIC), and residual heat removal (RHR) system Class 1 components exposed to reactor coolant or steam (with the RCS chemistry AMP)
2. Loss of material of the HPCI and RCIC system carbon steel components exposed to wetted gas (ISI AMP alone)
3. Loss of material and cracking of the HPCI, CS, RCIC, and RHR pump room copper cooling coils exposed to raw water (ISI AMP alone)
4. Loss of material of the HPCI and RCIC carbon steel piping exposed to reactor coolant (with the RCS chemistry AMP and the flow-accelerated corrosion (FAC) AMP)
5. Loss of fracture toughness of the cast austenitic stainless steel valve body of the PCIS exposed to reactor coolant (ISI AMP alone)

C. Auxiliary Systems

1. Loss of material and cracking of the standby liquid control (SBLC) and emergency cooling water (ECW) system stainless steel components exposed to borated water or outdoor environment (ISI AMP alone)
2. Loss of material of the SBLC carbon steel components and loss of material and cracking of the SBLC stainless steel components exposed to reactor coolant (with the RCS chemistry AMP)
3. Loss of material and cracking of the high-pressure service water (HPSW), emergency service water (ESW), and emergency cooling water (ECW) system Class 3 components exposed to raw water (with the Generic Letter 89-13 activities AMP)

D. Steam and Power Conversion Systems

1. Loss of material and cracking of the main steam system components exposed to steam (with the RCS chemistry AMP)
2. Loss of material and cracking of the main steam system components exposed to wetted gas and loss of material of the feed water system components exposed to reactor coolant (ISI AMP alone)
3. Loss of material of the main steam system components exposed to steam (with the RCS chemistry AMP and the FAC AMP)

E. Component Supports of ASME Class 2 and 3 Piping and Equipment

Loss of material of component supports submerged in raw water or torus water or exposed to an outdoor environment (ISI AMP alone)

The applicant stated that the ISI AMP provides monitoring and inspection of the aging effects of loss of material, cracking, and loss of fracture toughness that could damage the affected pressure-retaining components and support members.

3.0.3.6.2 Staff Evaluation

The staff's evaluation of the ISI program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

Program Scope: The applicant stated that the AMP manages loss of material, cracking, and loss of fracture toughness of the ASME Class 1, 2, and 3 pressure-retaining components exposed to reactor coolant, borated water, raw water, steam, wetted gas, sheltered, and outdoor environments and the support members of ASME Class 2 and 3 piping and equipment submerged in raw water or torus water.

The program scope does not include the pressure-retaining components exposed to condensed storage tank (CST) water or torus water. In RAI B.1.8-1, the staff asked why these components have not been included in the scope of the ISI program AMP. In a letter dated June 24, 2002, the applicant stated that the aging management activities for the pressure-retaining components exposed to the condensate storage water environment are the Condensate Storage Tank Chemistry Activities (LRA Section B.1.4, which is reviewed in Section 3.0.3.4 of this SER). The aging management activities for the pressure-retaining components exposed to the torus water environment are the Torus Water Chemistry Activities (LRA Section B.1.5, which is reviewed in Section 3.0.3.5 of this SER). The applicant stated that it verified the effectiveness of these programs using plant operating experience. Piping inspections are routinely performed in accordance with the ISI and FAC programs. Much of piping exposed to CST water or torus water is ASME Section XI class 2 piping, which requires periodic inspections of welds and pressure tests to verify integrity. In addition, the FAC program requires inspections at several susceptible locations to verify required wall thickness.

The staff noted that the LRA does not specify whether small-bore piping is included within the scope of the ISI program. The staff believes that a one-time inspection is adequate for small-bore piping (diameter < 4 inches) because it is exempted from ASME Code Section XI ISI and, thus, does not receive volumetric examination during ISI. In RAI B.1.8-5, the staff requested a clarification as to whether small-bore piping is included within the scope of the ISI program. In a letter dated April 29, 2002, the applicant explained that the small-bore piping is included in the scope of the ISI program. The ISI program requires system hydrostatic pressure testing that includes the small-bore piping in accordance with Section XI of the ASME Code. In addition, aging of small-bore piping is managed by aging management activities such as Reactor Coolant System Chemistry (LRA Section B.1.2), Condensate Storage Tank Chemistry Activities

(LRA Section B.1.4), Closed Cooling Water Chemistry (LRA Section B.1.3), or Torus Water Chemistry Activities (LRA Section B.1.5), as applicable. Small bore piping has experienced cracking as a result of stress corrosion and thermal cycling resulting from turbulent penetration and thermal stratification. However, as discussed in Section 3.1.3.2.1 of this SER these aging effects were determined to be not applicable for Peach Bottom small-bore Class 1 piping. Therefore, the ISI program is adequate for Peach Bottom small-bore Class one piping.

In response to RAIs B.1.8-1 and B.1.8-2, the applicant stated that the ISI program is not credited with managing the aging effects of ASME Code class piping in several plant systems, including HPCI, core spray, PCIS, RCIC, and RHR. Instead, the applicant stated the aging was adequately managed by Reactor Coolant System Chemistry (B.1.2), Condensate Storage Tank Chemistry Activities (B.1.4), Closed Cooling Water Chemistry (B.1.3), or Torus Water Chemistry Activities (B.1.5), as applicable. These programs provides chemistry controls only and do not include provisions for any inspections to verify the effectiveness of the programs. Water chemistry programs are designed to mitigate aging effects and not designed to confirm that the aging effect has not occurred. Confirmation of the effectiveness of chemistry programs is needed because they may not be effective in managing aging effect particularly in low or stagnant flow areas and lead to unacceptable degradation. Therefore, it is the staff's position that the applicant should perform inspections, through either the ISI program or one-time inspections, which are credited for license renewal, to verify the effectiveness of the chemistry program credited for managing the effects of aging. **This is Open Item 3.0.3.6.2-1.**

Preventive Actions: The applicant described this AMP as a condition inspection AMP. The applicant did not provide any preventive or mitigation actions for this activity, nor did the staff identify a need for such.

Parameters Monitored or Inspected: The applicant described the parameters to be monitored or inspected per ASME requirements. They are as follows:

A. Raw water and torus water

1. VT-3 visual inspection for corrosion for submerged support members
2. Identification of leakage during flow test and pressure test for monitoring loss of material and cracking for various service water system components exposed to raw water

B. Outdoor

VT-3 visual inspection for corrosion of components in outdoor environment.

C. Steam

1. Identification of leakage during pressure test for monitoring loss of material and cracking for ASME Class 1 components in the main steam, reactor vessel instrumentation, HPCI, and RCIC systems
2. Visual inspection of valves in the main steam and HPCI systems for corrosion when they are disassembled for maintenance

D. Reactor Coolant

1. Monitoring of leakage during pressure test for management of loss of material and cracking for ASME Class 1 components in the reactor recirculation, reactor vessel instrumentation, SBLC, feedwater, RHR, RCIC, core spray, HPCI, and PCIS systems
2. Visual inspection of valves and pumps in the reactor recirculation, RHR, core spray, and PCIS systems for corrosion when they are disassembled for maintenance
3. Surface and volumetric examinations of reactor pressure vessel studs for cracking
4. Crack monitoring of susceptible ASME Class 1 components in the reactor recirculation, RHR, core spray, and PCIS systems by surface and volumetric examinations of pressure retaining welds and heat-affected zones in piping

E. Borated Water

Monitoring of leakage during pressure test for management of loss of material and cracking for the SBLC system components

F. Wetted Gas

Monitoring of leakage during pressure test for management of loss of material and cracking for the RCIC and HPCI system components exposed to wetted gas.

The staff finds the parameters monitored to be acceptable because they are linked to the degradation of the system and component intended functions and would adequately detect the presence and extent of the aging effects.

Detection of Aging Effects: The applicant stated that the test techniques, extent, and schedule of the ISI AMP are based on the requirements of ASME Section XI. These are designed to maintain component structural integrity and ensure that aging effects will be detected and repaired before the loss of the intended function of the component. The staff agrees that the applicant’s AMP has an adequate inspection schedule, inspection techniques, and inspection scope, and thus the aging effects will be detected before there is loss of component intended function.

Monitoring and Trending: The applicant stated that documentation for comparison with previous and subsequent inspections is maintained in accordance with ASME Section XI, IWA-6000. The staff finds the approach acceptable because comparison with previous and subsequent inspections would provide data for trending and provide predictability of the extent of degradation so timely corrective or mitigative actions are possible.

Acceptance Criteria: The applicant evaluates degradation detected during tests or inspections in accordance with ASME Section XI IWB-3000, IWC-3000, or IWD-3000 for Class 1, 2, and 3 components, respectively. Degradations detected in support members are evaluated in accordance with ASME Code Case N-491-1. The staff finds that these criteria are acceptable because they are based on the ASME Code.

Operating Experience: The applicant stated that PBAPS has implemented extensive inspection programs through the ISI program to identify IGSCC. The LRA, however, does not describe the operating experience and the effectiveness of the inspection program in the identification of IGSCC. In RAI B.1.8-4, the staff requested information on the operating experience and the effectiveness of the inspection program in the identification of IGSCC. In a letter dated April 29, 2002, the applicant stated that prior to 1988, cracking attributed to IGSCC was found in stainless steel recirculation and RHR system piping. Portions of the "304 stainless" steel recirculation system, RWCU, and RHR piping were replaced with more IGSCC resistant, low carbon "316 stainless" steel. Subsequent to 1988, IGSCC has been identified in the RWCU system, core spray downcomer piping, core shroud, and jet pump riser piping. The identified cracking was dispositioned as meeting the applicable acceptance criteria either by repair or by analysis. The applicant stated that the ISI program, including the augmented inspections to address GL 88-01, has been effective in identifying IGSCC prior to loss of system intended functions. The staff finds that the plant operating experience has demonstrated the effectiveness of the AMP, and that the applicant has incorporated lessons learned from operating experience into the development of this program.

3.0.3.6.3 UFSAR Supplement

The staff reviewed Section A.1.8 of the UFSAR Supplement (Appendix A of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

3.0.3.6.4 Conclusions

The staff concludes that, with the exception of Open Item 3.0.3.6.2-1, the applicant has demonstrated that the aging effects associated with the ISI program will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.0.3.7 Primary Containment Inservice Inspection Program

The applicant described the primary containment ISI program in Section B.1.9 of Appendix B to the LRA. The applicant credits the program to manage loss of material in the primary containment for Class MC pressure-retaining components, their integral attachments, and Class MC component supports, and loss of sealing for the drywell internal moisture barrier at the juncture of the containment wall and the concrete floor. The staff has reviewed this section of the application to determine whether the applicant has demonstrated that the effects of aging will be adequately managed by the IST program during the extended period of operation as required by 10 CFR 54.21(a)(3).

3.0.3.7.1 Technical Information in the Application

In its description of the program, the applicant indicated that the containment ISI program provides for inspections that manage loss of material in the primary containment for Class MC pressure-retaining components, their integral attachments, and Class MC component supports; and loss of sealing for the drywell internal moisture barrier at the juncture of the containment wall and the concrete floor. The applicant further indicated that the program complies with subsection IWE of ASME Section XI, 1992 Edition including 1992 Addenda, in accordance with the provisions of 10 CFR 50.55a, and is implemented through a PBAPS specification. The applicant stated that Class MC support inspection meets the support examination criteria established by Code Case N-491-1.

The applicant also addresses the 10 elements of a typical AMP, as relevant to the Primary Containment ISI program. These elements are discussed in Section B.1.9.2 of the LRA.

The applicant concludes that on the basis of compliance with industry standards and operating experience, the primary containment ISI program will continue to adequately manage the identified aging effects such that the primary containment intended functions will be maintained consistent with the CLB for the period of extended operation.

3.0.3.7.2 Staff Evaluation

The staff evaluation of the primary containment ISI program focused on how the ISI activities manage aging effects through the effective incorporation of the following 10 elements: scope of program, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls part of the site-controlled quality assurance program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining seven elements are evaluated below.

Program Scope: The primary containment ISI program manages loss of material in pressure boundary components and supports of the drywell, pressure suppression chamber, and vent system. The components monitored in the drywell are the shell, head, control rod drive removal hatch, equipment hatch, personnel airlock, access manhole, inspection ports, and penetration sleeves. The components monitored in the pressure suppression chamber are the shell, ring girders, access hatches and penetrations. The components monitored in the vent system are the vent lines, vent header with downcomers, downcomer bracing, and vent system supports. The primary containment ISI program also manages loss of sealing for the moisture barrier inside the drywell at the juncture of the containment wall and the concrete floor.

The structural components included in the scope cover the essential pressure-retaining components of the containment structure. However, the LRA was not clear as to whether the program includes the examination and testing of the pressure retaining bolts associated with the primary containment components (e.g., equipment hatch, drywell head). In RAI B.1.9-1 the staff requested clarification concerning the examination and the testing of bolts. In response, the applicant stated that the visual examination of pressure retaining bolts is in accordance with IWE-3510.3, and testing of the bolts will be part of Appendix J, Type B tests.

The staff considers the scope of the program adequate and acceptable, as the applicant will perform visual examination of the pressure retaining bolts in accordance with the requirements of IWE-3510.3 and confirm the bolts pressure retaining capacity during Type B testing as required by Appendix J on the basis of conformance with the ASME standard.

Preventive Actions: The primary containment ISI program utilizes inspections for detection of degraded conditions. No preventive or mitigating attributes are associated with these activities. In describing the "Operating Experience," the applicant mentions the instances of coating degradation in PBAPS containment structures. It is not clear why the applicant does not consider maintenance of coating on the inside surfaces of the containment structures as part of the preventive actions. In response to the staff's RAI B.1.9.2, the applicant stated that the protective coating does not perform a license renewal function as defined in 10 CFR 54.4(a)(1), (2), or (3), and is not credited in the determination of aging effects requiring aging management of the torus. The staff believes that coating provides a preventive measure in alleviating the chances of corrosion. However, the applicant is correct in pointing out that the protection coating does not perform a license renewal function as defined in 10 CFR 54.4(a); therefore the applicant's response is acceptable.

Parameters Monitored or Inspected: The primary containment ISI program provides for visual examination of containment surfaces and Class MC component supports for evidence of loss of material that could affect structural integrity or leak-tightness of the primary containment. The moisture barrier is examined for wear, damage, erosion, tears, cracks or, other defects that could affect leak-tightness. The staff finds this parameter monitored by the program reasonable and acceptable.

Detection of Aging Effects: The applicant stated that the method, extent, and schedule of the primary containment ISI program visual examinations provide reasonable assurance that evidence of loss of material or loss of sealing is detected prior to loss of intended function. The staff agrees that the visual examinations performed in accordance with subsection IWE ISI program will detect the applicable aging effects, and finds the detection of aging effects acceptable.

Monitoring and Trending: The LRA states that the primary containment ISI program provides for periodic monitoring for the presence of aging degradation in accordance with the guidance provided in ASME Section XI. In RAI B.1.9-4, the staff requested an explanation for the use of ASME Section XI as a guidance document. In response, the applicant confirmed that the PBAPS primary containment ISI program complies with the requirements of the 1992 Edition and the 1992 Addenda of Subsection IWE of ASME Code, Section XI, as incorporated by reference in 10 CFR 50.55a, and their use is mandatory. With this clarification, the staff considers that the monitoring and trending in accordance with the IWE ISI program is acceptable.

Acceptance Criteria: The acceptance criteria for the drywell, pressure suppression chamber, vent system, and drywell moisture barrier are in accordance with the requirements of ASME XI, Subsection IWE. Class MC component supports acceptance criteria are in accordance with Code Case N-491-1. The staff has accepted the use of Subsection IWE and Code Case N-491-1 acceptance criteria as part of the current licensing requirements. The staff considers these criteria acceptable since they conform to the ASME Code or NRC-approved Code Cases.

Operating Experience: Indications of coating degradation and loss of material in certain wetted areas of the pressure suppression chamber structure were found at PBAPS in 1991. The interior surfaces were recoated and the torus-grade water chemistry was improved. Subsequent pressure suppression chamber inspections indicate that the rate of degradation has decreased significantly. No failure of containment components due to the loss of material or failure of the moisture barrier inside the drywell due to the loss of sealing has occurred at PBAPS. The development process for the ASME Code that forms the basis for the primary containment ISI program includes review and approval by industry experts, thereby assuring that industry data has been considered.

To get a better understanding of the applicant's procedures and criteria, in RAI B.1.9-5 and B.1.9-6 the staff requested additional information regarding the PBAPS operating experience related to the degradation of the tori. In letter dated April 29, 2002, the applicant provided the following summary.

> PBAPS examination program for wetted and submerged surfaces on the interior of the suppression chamber (torus) in both units was established in 1991. Underwater visual examinations were performed on the interior torus surfaces, and pit depth measurements were taken on one square foot evaluation areas that were selected in each of the 16 bays, based on having the greatest concentration of deep pits. In conjunction with underwater examinations, ultrasonic thickness measurements were taken on the defined evaluation areas from the outside of the torus at the pitted areas. Examination results showed that the maximum measured pit depth approached a depth of 10% of the shell's wall thickness. The average measured pit depth in unit 2 torus was 25 mils, while the average measured pit depth in unit 3 was 31 mils.
>
> The degradations were dispositioned by a combination of corrective actions and engineering evaluation. The evaluation concluded that the structural integrity of the torus in both units was maintained, and continued operation was justified. The evaluation also established inspection methodology and acceptance criteria for future examinations. These requirements are incorporated in the "augmented" inspection of the torus under the Primary Containment ISI Program.
>
> Water chemistry is determined to be the primary cause of the degradation as evidenced by the reduced rate of corrosion since 1991 when improved water chemistry controls were established. However other factors such as possible loss of protective coatings, lamination or potential flaws in the rolled steel plate, and micro-organisms present in the accumulated sludge may have contributed to the degree of the degradation.
>
> As for location of the degradations, our inspections found the pits to be randomly distributed along the submerged surface of the torus. The worst pits were found is areas where protective coating was lost due to damage during construction or misapplication. These degradations were found near the bottom of the torus at approximately 30-degree angle from the vertical. The area near the strainers was not significantly different from the rest of the torus.

Under operating experience, the LRA states that the rate of depression chamber degradation reduced significantly, following recoating of the torus and improving torus chemistry. In RAI B.1.9-6, the staff requested information about the projected torus wall thickness at the end of the period of extended operation, and whether it was sufficient to the support the CLB. By letter dated April 29, 2002, the applicant provided the response.

PBAPS Unit 2 torus shell was inspected in October 1998 to evaluate pit growth rate since the 1991 inspection. The corrosion evaluation area selected for inspection contained 30 pits inspected in November 1991, eight (8) of which were repaired via application of underwater coating. The 1998 inspection results showed that coating repairs remained in tact. The average change in pit depth is less than 5 mils over the seven (7) year time period between inspections, or 0.7 mils annual rate. Actual pit depths from the 22 measured pits ranged from a low of 17.0 mils to a high of 41.1 mils.

Similarly PBAPS Unit 3 torus shell was inspected in October 1997. The evaluation area inspected contained 18 pits, which were inspected in January 1991. The average change in pit depth is less than 3 mils over the six (6) year time period between inspections, or 0.5 mils annual rate. Actual pit depths from the 18 measured pits ranged from a low value of 16.3 mils to high value of 46.1 mils.

The design shell thickness of the immersion area of the torus is 675 mils. Using the average corrosion rates and deepest pits above, the projected estimated worst pit through the end of extended term of operation for Unit 2 is 65.6 mils (41.1 mils + 35 years x 0.7 mil) and 64.1 mils for Unit 3 (46.1mils + 36 years x 0.5 mils). Thus the minimum projected thickness at the pitted area at the end of 60 years is 609.4 mils for Unit 2 and 610.9 mils for Unit 3.

Engineering analysis shows that the impact of pits on local and global structural integrity of the torus is a function of the width of the pit, as well as its depth. Evaluation performed, after 1991 inspections, concluded a pit depth of 65 mils has no impact on torus structural integrity regardless of the pit diameter. Thus, the overall thickness of the torus can be reduced by 65 mils without impacting its intended functions. This would indicate that control of torus water chemistry alone is adequate to manage aging of the torus shell loss of material. However, considering industry experience with torus degradations, as well as PBAPS past experience, the Primary Containment ISI Program (Augmented Inspections) is considered more effective for managing this aging effect.

As a result, the Exelon is committed to continued periodic inspection of the torus shell for loss of material as defined in Primary Containment ISI Program. Identified defects will be evaluated against established design basis criteria or corrected to ensure the intended functions of the torus are maintained through the extended term of operation.

In response to RAI B.1.9-7 related to the degradation of PBAPS drywells, the applicant stated in a letter dated April 29, 2002, that it has not identified any degradation on the drywell shells.

The staff finds that the PBAPS operating experience shows the containment ISI program has been successful in identifying aging effects as described.

3.0.3.7.3 UFSAR Supplement

The staff reviewed Section A.1.9 of the UFSAR Supplement (Appendix A of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

3.0.3.7.4 Conclusions

The staff concludes that the applicant has demonstrated that the aging effects associated with primary containment ISI program will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.0.3.8 Primary Containment Leakage Rate Testing Program

The applicant described the primary containment leakage rate testing program in Section B.1.10 of Appendix B to the LRA. The applicant credits the program to manage the loss of material of pressure retaining boundaries of piping and components in a wetted gas environment for the containment atmosphere control and dilution, RHR, and primary containment isolation systems. The applicant also credits the program to manage change in the material properties and cracking of gaskets and O-rings of the primary containment pressure boundary access penetration points. The staff has reviewed the section of the application to determine whether the applicant has demonstrated that the effects of aging will be adequately managed by the IST program during the extended period of operation as required by 10 CFR 54.21(a)(3).

3.0.3.8.1 Technical Information in the Application

In the introductory paragraph, the applicant states: "The PBAPS Primary Containment Leakage Rate Testing Program complies with the requirements of 10 CFR Part 50 Appendix J, Option B. Containment leak rate tests are performed to assure that leakage through the primary containment and systems and components penetrating primary containment does not exceed allowable leakage rates specified in the PBAPS Technical Specifications. An integrated leak rate test (ILRT) is performed during a period of reactor shutdown at a frequency of at least once every 10 years. Local leak rate tests (LLRT) are performed on isolation valves and containment pressure boundary access penetrations at frequencies that comply with the requirements of 10 CFR Part 50 Appendix J, Option B."

The applicant also addresses the 10 elements of a typical AMP, as relevant to the Primary Containment Leakage Rate Testing Program. These elements are discussed below.

Based on the content of the program description, the applicant concluded that there is reasonable assurance that the primary containment leakage rate testing program activities will continue to adequately manage loss of material, change in materials, and cracking of the identified primary containment components to preclude loss of intended function and maintain the CLB during the period of extended operation.

3.0.3.8.2 Staff Evaluation

The staff evaluation of the Primary Containment Leakage Rate Testing Program focused on how the activities managed aging effects through the effective incorporation of the following 10 elements: scope of program, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining seven elements are evaluated below.

Scope of Program: The primary containment leakage rate testing program is credited with managing the loss of material of pressure retaining boundaries of piping and components in a wetted gas environment for containment atmosphere control and dilution, RHR, and primary containment isolation systems. Two types of tests are implemented in the program. The ILRT is performed to measure the overall primary containment integrated leakage rate. LLRTs are performed to measure local leakage rates across each pressure containing or leakage-limiting boundary for the primary containment isolation system containment penetrations. The method, extent, and schedule of these tests will detect minor leakage prior to loss of intended function. The primary containment leakage rate testing program also manages change in the material properties and cracking of gaskets and O-rings of the primary containment pressure boundary access penetration points, including the drywell head, the equipment hatch, the airlock, control rod drive removal hatch, drywell head access hatch, stabilizer inspection ports, and the two access hatches in the pressure suppression chamber.

The applicant has adequately described the components of the primary containment structures for which the leak-tight integrity will be assured by the program. The applicant also emphasizes that the program will also detect the changes in material properties and cracking of gaskets and O-rings of the primary containment pressure boundary components. The staff considers the scope of activities related to the program adequate and acceptable.

Preventive Actions: The primary containment leakage rate testing program does not prevent or mitigate degradation due to aging effects but provides measures for condition monitoring to detect the degradation prior to loss of intended function. However, the staff considers the Primary Containment ISI Program, as evaluated in Section 3.0.3.7 of this SER, as a complementary program in detecting aging effects and in reducing potential leakage through the pressure-retaining components of the PBAPS primary containments. The staff considers the description of the element acceptable, as the staff agrees with the applicant's statement that the program, by itself, does not prevent or mitigate degradation due to aging effects.

Parameters Monitored or Inspected: The parameters monitored are leakage rates through penetrations, piping, valves, fittings, and other access openings. The ILRT is a test of the pressure retaining capabilities of the containment as a whole. The LLRTs measure the pressure retaining integrity of individual containment penetrations and the local leak rate at access penetration points of the containment pressure boundary. Gaskets and O-rings not meeting the allowable leakage rate are assumed to be degraded, and are visually examined, replaced, and retested until the leakage rate is acceptable. The staff finds the parameters monitored to be acceptable as they are in accordance with the requirements of Appendix J of 10 CFR Part 50.

Detection of Aging Effects: The primary containment leakage rate testing program detects containment pressure boundary piping and component loss of material by integrated containment and individual penetration pressure tests. These tests verify the pressure retaining integrity of the containment. The ILRT demonstrates the overall leak-tightness of the containment and systems within the containment boundaries. LLRTs demonstrate the leak-tightness of individual containment boundaries of the piping systems. The program also detects local leaks and measures leakage across the leakage-limiting boundary of containment access penetrations whose design incorporated gaskets and O-rings. Leakage is an indication of change in material properties and cracking of the sealing materials. The primary containment leakage rate testing program serves to detect aging degradation prior to loss of the pressure boundary function of selected portions of the primary containment. The leakage testing is capable of detecting the applicable aging effects; therefore, this element is acceptable.

Monitoring and Trending: Since the primary containment leakage rate testing program must be repeated throughout the operating license period, the entire primary containment pressure boundary, including access penetrations whose design incorporated gaskets and O-rings, is being monitored and trended over time. The staff finds the trending to be acceptable, and finds its continuation during the extended period of operation will continue to monitor the essential leak-tight characteristics of the containment.

Acceptance Criteria: The acceptance criteria are defined in the PBAPS Technical Specifications. These acceptance criteria meet the requirements in 10 CFR Part 50, Appendix J, Option B. The staff considers the use of the acceptance criteria defined in the PBAPS Technical Specifications acceptable for this program because the criteria verify that the plant remains within its CLB.

Operating Experience: The primary containment leakage rate testing program activities at PBAPS have been effective in maintaining the pressure integrity of the containment boundaries, including identification of leakage within the containment atmosphere control and dilution, RHR, and primary containment isolation system pressure boundaries. Degradation due to loss of material and failure of pressure boundary function has not occurred in any of the portions of these systems subjected to a wetted gas environment. The program found no age-related pressure boundary integrity failures due to local leakage for gaskets and O-rings at penetration access points, including the drywell head, the equipment hatch, the airlock, control rod drive removal hatch, drywell head access hatch, stabilizer inspection ports, and the two access hatches in the pressure suppression chamber. Consequently, the program has been effective in preventing unacceptable leakage through the containment pressure boundary. PBAPS continues to demonstrate its good operating history by electing to perform Option B of 10 CFR Part 50 Appendix J test requirements.

The staff requested additional information regarding the operating experience related to the testing of vent bellows at PBAPS. In RAI B.1.10-3, the applicant provided the following response:

> The PBAPS vent line bellows are 2-ply type, constructed to be tested locally, and subject to 10 CFR [Part] 50, Appendix J, Type B Test. The LLRT method implemented at PBAPS verifies no internal blockage of flow to avoid the inconsistency reported in NRC Information Notice 92-20. Recent Local Leak Rate Test (LLRT) records (1992, 1994, and 1998) for the Unit 2 vent line bellows indicate that leakage through each bellow is significantly less than the assigned administrative limit. Similar results were recorded for Unit 3 vent line bellows during the previous three LLRTs (1993, 1995, and 1999). Periodic Type A ILRT results have not shown inconsistencies with the LLRT results described in the Information Notice 92-20.

The staff finds that operating experience demonstrates that the containment Primary Containment Leakage Rate Testing Program has been successful in identifying aging effects. This program provides reasonable assurance that the containment leak rate will be maintained within the Technical Specification limits.

3.0.3.8.3 UFSAR Supplement

The staff reviewed Section A.1.10 of the UFSAR Supplement (Appendix A of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

The staff requested a clarification in RAI B.1.10-4 of the summary statement, “The primary containment leakage rate testing program is that portion of the PBAPS primary containment leakage rate testing program that is being credited for license renewal.” In a letter dated April 29, 2002, the applicant provided the following clarification:

> The Primary Containment Leak Rate Testing Program includes Type A, Type B and Type C tests for all of primary containment and isolation components. But the only part of the program that is credited for license renewal is what is included the scope of the AMA App B.1.10, attribute 1. That is, the Program is credited for managing loss of material of pressure retaining boundaries of piping and components in a wetted gas environment for containment atmosphere control and dilution, RHR, and primary containment isolation systems. The Program is also credited for managing change in material properties and cracking of gaskets and O-rings of the primary containment pressure boundary access penetration points including the drywell head, the equipment hatch, the airlock, control rod drive removal hatch, drywell access hatch, stabilizer inspection ports and the two access hatches in the pressure suppression chamber.

On the basis of the description in the LRA that states: “Two types of tests are implemented in the program. The ILRT is performed to measure the overall primary containment integrated leakage rate. LLRTs are performed to measure local leakage rates across each pressure containing or leakage limiting boundary for the primary containment isolation system containment penetrations,” and the further elaboration provided in this response, the staff considers the applicant’s response acceptable.

3.0.3.8.4 Conclusions

The staff concludes that the applicant has demonstrated that the aging effects associated with primary containment leakage rate testing program will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.0.3.9 Reactor Pressure Vessel and Internals Inservice Inspection Program

3.0.3.9.1 Technical Information in the Application

In Sections A.2.7 and B.2.7 of the LRA, the applicant describes an enhanced aging management program, the Reactor Pressure Vessel and Internals ISI Program, which is composed of 13 Boiling Water Reactor Vessel and Internals Project (BWRVIP) inspection and evaluation (I&E) reports for reactor pressure vessel and internals components, 10 of which address both the current term and license renewal. The BWRVIP program provides for periodic inspections to monitor the condition of each internal BWR component that could impact safety, enabling degradation to be detected before the component’s function is adversely affected.

With regard to license renewal, the BWRVIP I&E reports specifically address the internals relative to the requirements of 10 CFR Part 54. The staff’s SERs on the BWRVIP I&E reports established the adequacy of the generic BWRVIP reports for license renewal by concluding that the license renewal rule provisions have been satisfied, including the identification and assessment of aging effects, the evaluation of the adequacy of those programs with regard to those aging effects, and demonstration that these programs will assure the functionality of internals into the renewal term.

The applicant has evaluated the BWRVIP program for its applicability to the Peach Bottom Units 2 and 3 design, construction, and operating experience, stating that the RPV and vessel internals, including the materials of construction, are addressed by the BWRVIP program I&E reports and that the plant operation parameters, including temperature, pressure, and water chemistry, are consistent with those used for the development of the I&E reports. The applicant has determined that the components, which require aging management review in accordance with the license renewal rule, are covered by the referenced BWRVIP program reports, and that the referenced BWRVIP program reports cover the design of the Peach Bottom RPV and all vessel internals.

The BWRVIP program provides for periodic inspections to monitor the condition of each RPV and vessel internals component that could impact safety, enabling degradation to be detected before the component’s intended function is adversely affected. The applicant stated that the RPV components requiring aging management within the scope of license renewal are the components evaluated in BWRVIP-74: vessel shells, attachments to the vessel inside surface, nozzle safe ends, core ΔP/SLC nozzles, CRDH stub tubes, ICM housing penetrations, and instrument penetrations. The applicant also stated that the vessel internals requiring aging management within the scope of license renewal are the shroud, shroud supports, core support plate, core ΔP/SLC line, access hole covers, 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 reactor internals are examined using a combination of ultrasonic, visual, and surface inspection methods. The methods to be used and the frequency of examination are specified in the applicable BWRVIP inspection and evaluation document, unless specific exception has been identified to, and approved by, the staff. Therefore, the applicant has established that the BWRVIP program reports bound the Peach Bottom design and operation with the following two exceptions: (1) feedwater nozzles are examined using BWROG alternative to GL 81-11, "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking," (NUREG-0619) augmented inspection of feedwater nozzles for thermal cycle cracking, and (2) the access hole covers for Peach Bottom Unit 2 are examined according to GE SIL 462.

3.0.3.9.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the Sections A.2.7 and B.2.7 of the LRA to determine whether the applicant has demonstrated that the applicable aging effects will be adequately managed so that system intended functions will be maintained, consistent with the CLB for the period of extended operation.

The staff evaluation of the Reactor Pressure Vessels and Internals Inservice Inspection (ISI) program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicates that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

Program Scope: In Section B.2.7 of the LRA, the applicant stated that the RPV components requiring aging management within the scope of license renewal are the components evaluated in BWRVIP program which include vessel shells, attachments to the vessel inside surface, nozzle safe ends, core ΔP/SLC nozzle, CRDH stub tubes, ICM housing penetrations, and instrument penetrations. The applicant also stated that the vessel internals requiring aging management within the scope of license renewal include the shroud, shroud supports, access hole covers, core support plate, core ΔP/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 staff finds that the relevant components are included in the scope of the Reactor Pressure Vessel and Internals Inservice Inspection (ISI) Program and therefore the scope is adequate.

The staff has written safety evaluations (SEs) of the BWRVIP reports identified in the table below and their associated license renewal appendices. In most instances, the staff's SEs contain generic open items and recommendations and applicant-specific license renewal action items. In RAI 3.1-18, the staff requested that the applicant identify and discuss, in a plant-specific manner, how the applicant is addressing each generic open item and recommendation and the applicant-specific action items, in the staff's SEs for these BWRVIP reports and related license renewal appendices listed below. In addition, the staff requested the applicant to address specifically, 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 mockup.

B. The applicant should confirm that the holddown 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 adequate NDE method, in order to establish a baseline for these welds, and that an adequate reinspection schedule, based on adequate 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 that is capable of detecting IGSCC, and should 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 reinspection 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.

In addition, the staff requested that the applicant describe the BWRVIP generic and applicant-specific processes for ensuring that the BWRVIP generic reports, 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. In response to RAI 3.1-18, the applicant stated that 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). The staff considers the applicants response acceptable because it has committed to implement the BWRVIP program requirements for current and future activities. In addition, an inspection of the PBAPS reactor internals program was performed (NRC Inspection Report - 2002-010) and it was determined that the reactor internals inspection program was being augmented in accordance with the BWRVIP program that was previously approved by the NRC staff. This provided additional confirmation that the applicant has a program to include the BWRVIP program into its ISI program.

Preventive or Mitigative Actions: The subject AMP is a condition monitoring program which utilizes enhanced visual inspections, as well as volumetric and surface examinations, to detect loss of material in the reactor pressure vessel head and cracking in reactor pressure vessel components and vessel internals such that proper evaluations and corrective actions may be accomplished. Early detection and subsequent evaluation and corrective actions are considered adequate to detect degradation of reactor pressure vessel components and vessel internals before the component's intended function is adversely affected. There are no preventive or mitigative attributes associated with the subject program.

Parameters Inspected or Monitored: The subject AMP is based on the BWRVIP program, which has reviewed the function of each reactor pressure vessel and internals component. For those RPV and internals components that could impact safety, the BWRVIP program considered the mechanisms that might cause degradation of these components and developed an inspection program that would enable degradation to be detected and evaluated before the component's intended function was adversely affected. Details regarding inspection and evaluation are contained within the component-specific BWRVIP inspection and evaluation documents. The staff finds that the applicant has adequately characterized how the BWRVIP documents will assist in inspection and monitoring of RPV and internals components at Peach Bottom to identify and evaluate aging effects.

Detection of Aging Effects: The RPV components and reactor internals are examined using a combination of ultrasonic, visual, and surface methods. The examinations comply with the requirements of the 1989 Edition of ASME Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components." In addition, the examination methods to be used and the frequency of examination to be employed are specified in the applicable BWRVIP I&E reports, the BWROG report, "Alternative BWR Feedwater Nozzle Inspection Requirements," and General Electric Service Information Letter (SIL) 462 for the access hole cover. These examination methods and inspection frequencies are incorporated in the subject ISI program specification. The subject AMP also provides for visual inspections of the top head for loss of material.

The staff finds the detection methods, as specified, are adequate to characterize and evaluate age-related degradation in the RPV components and reactor internals before there is a loss of component intended function.

Monitoring and Trending: Monitoring of the detrimental effects of aging in RPV components and internals is specified in the BWRVIP I&E reports. The frequency of examination specified in applicable BWRVIP I&E reports varies for each component or subassembly. The frequency is based on the component's design, flaw tolerance, susceptibility to degradation, and the method of examination used. In cases where a component may be inspected using either visual or ultrasonic methods, the interval between examinations is shorter when visual methods are used. The Peach Bottom corrective actions program provides for trending of significant indications noted during BWRVIP inspections.

The staff finds the adequate applicant's approach to monitoring and trending aging in components within the scope of the BWRVIP reports because it is consistent with the staff approved BWRVIP programs.

Acceptance Criteria: BWRVIP I&E reports provide the basis for Plant Peach Bottom reactor pressure and vessel internals inspection requirements, acceptance criteria, and proper corrective actions. The applicant has incorporated these applicable I&E reports into the Plant Peach Bottom LRA by specific reference. BWRVIP I&E reports applicable to PBAPS RPV and vessel internals components are as follows:

Component	**Reference**	**SER Date**	**Accession # for SER**
Reactor pressure vessel components	BWRVIP-74	10/18/01	ML012920549
Vessel shells	BWRVIP-05	03/07/00	ML003690281
Shroud support and attachments	BWRVIP-38	03/01/01	ML010600211
Shroud	BWRVIP-76	To be completed by 12/31/02	N/A
Nozzle safe ends	BWRVIP-75	09/15/00	ML003751105
Core support plate	BWRVIP-25	12/07/00	ML003775989
Core ΔP/SLC line and nozzle	BWRVIP-27	12/20/99	ML993630179
Core spray, jet pump riser brace, and other attachments	BWRVIP-48	01/17/01	ML010180493
Core spray lines and spargers	BWRVIP-18	12/07/00	ML003775973
Top guide	BWRVIP-26	12/07/00	ML003776810
Jet pump assemblies	BWRVIP-41	06/15/01	ML011310322
CRDH stub tubes and guide tubes, ICM housing guide tubes and penetrations	BWRVIP-47	12/07/00	ML003775765
Instrument penetrations	BWRVIP-49A	03/31/02	ML021510061
Integrated Surveillance Program Plan	BWRVIP-78	To be completed 2003	N/A
Intergrated Surveillance Program: Implementation Plan	BWRVIP-86	To be completed 2003	N/A

The acceptance criteria for cracking in the feedwater nozzle are presented in the industry report GE-NE-523-A71-0594-A, Revision 1, "Alternate BWR Feedwater Nozzle Inspection Requirements," May 2000. The staff finds that the acceptance criteria, as presented in the referenced BWRVIP reports and in GE-NE-523-A71-0594-A, Revision 1, are acceptable. While the review of BWRVIP-76 and -78 have not been completed PBAPS has indicated by letter dated May 6, 2002, that they will incorporate the approved BWRVIP programs into the aging management activities.

In addition, for open issues between the BWRVIP and NRC, Exelon will work as part of the BWRVIP to resolve these issues generically while the staff's review of BWRVIP-78 and BWRVIP-86 is continuing. And while the proposed ISP addressed by BWRVIP-78 and BWRVIP-86 only applies to the period of the current operating license, the BWRVIP has committed to provide supplemental information to extend the ISP through the period of extended operation, based on the same technical criteria as found in BWRVIP-78 and BWRVIP-86 for the BWR fleet. The staff expects this supplemental information to be submitted in 2002 and 2003.

Although the BWRVIP-78 and -86 reports apply only to the current term, the staff finds that the provisions in these reports, if implemented during the extended period of operation, constitute sufficient actions to manage the aging effects associated with the reactor vessel during the renewal term.

On the basis of these commitments, the staff concludes that the applicant has identified in sufficient detail the actions that will be taken to provide reasonable assurance that aging effects associated with embrittlement of the reactor vessel will be adequately managed for the period of extended operation. The renewed license will be conditioned to require that prior to operation in the renewal term, the applicant will notify the NRC of its decision to implement the ISP or a plant-specific program, and provide the adequate revisions to the UFSAR Supplement summary descriptions of the vessel surveillance material testing program.

Operating Experience: The applicant has made a general statement that the degradations found at Peach Bottom are similar to those reported in the industry and most of them are attributed to cracking. The applicant further states that the program is based on BWRVIP guidelines, which relied on extensive review of applicable industry operating experiences and examination results to develop adequate inspection and evaluation guidelines. The BWRVIP program is an industry-wide effort based on over 20 years of service and inspection experience and is focused on detecting evidence of component degradation well before significant degradation occurs. The BWRVIP inspection and evaluation reports for reactor pressure vessel and internals components were submitted to the NRC for review and approval. These inspection and evaluations reports address both the current and license renewal periods. The applicant further stated that the BWRVIP program was reviewed for its applicability to PBAPS design, construction, and operating experience. Therefore, it was concluded that the BWRVIP inspection and evaluation reports bound PBAPS design and operation.

3.0.3.9.3 UFSAR Supplement

The staff reviewed Section A.2.7 of the UFSAR Supplement (Appendix A of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

The applicant describes the reactor pressure vessel and internals ISI program as an enhanced aging management program in Section A2.7 of the LRA. The program provides for condition monitoring of the reactor pressure vessel and internals. The program complies with the requirements of an NRC-approved Edition of the ASME Section XI Code, or its approved alternative. The program has been augmented to include various additional requirements, including those from the BWRVIP guidelines, BWROG alternative to NUREG-0619 inspection of feedwater nozzle for GL 81-11 thermal cycle cracking, and GE SIL 462 for examination of the access hole cover. In RAI 3.1-18, the staff requested the applicant to 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). In response, the applicant stated that Exelon 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). The staff finds the applicant response to the part of RAI 3.1-18 related to the UFSAR Supplement (Appendix A of the LRA) is acceptable because it adequately described the reactor pressure vessel and internals ISI program.

3.0.3.9.4 Conclusions

The staff concludes that the applicant has demonstrated that the aging effects associated with reactor pressure vessel and internals ISI program will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.0.3.10 Inservice Testing Program

The applicant described the Inservice Testing (IST) program in Section B.1.11 of Appendix B to the LRA. The applicant credits the testing under the PBAPS IST program with managing the effects of aging of flow blockages in the emergency service water system (ESW) and emergency cooling water system (ECW) components exposed to raw water. In addition, the program manages heat transfer reduction of the RHR heat exchangers through flow testing of the torus water path. The staff has reviewed Section B.1.11 of the LRA to determine whether the applicant has demonstrated that the effects of aging will be adequately managed by the IST program during the extended period of operation as required by 10 CFR 54.21(a)(3).

3.0.3.10.1 Technical Information in the Application

The IST program that is being credited for license renewal is a portion of the PBAPS IST program. The PBAPS IST program is implemented by a PBAPS specification and provides for inservice testing of Class 1, 2, and 3 pumps and valves in compliance with the ASME O&M Code, 1990 Edition, and 10 CFR 50.55a. The staff reviewed and approved the IST program.

As identified in Chapter 3, Tables 3.2-5, 3.3.6, and 3.3.14, of the LRA, the IST program is credited for managing flow blockages in the ESW and ECW components exposed to raw water and for managing heat transfer reduction for the torus water path through the RHR heat exchangers. The applicant's description of the program addressing the seven program elements is discussed in Section 3.0.3.8.2 of this SER. In Section B.1.11 of the LRA, the applicant concluded that based on the application of industry standards and the PBAPS operating experience, there is reasonable assurance that the IST program will continue to provided method for early detection of flow blockage and heat transfer reduction of the RHR heat exchangers through flow testing of the torus water path so that intended functions of the components will be maintained consistent with the CLB through the period of extended operation.

3.0.3.10.2 Staff Evaluation

The staff evaluation of the IST program focused on how the activities managed aging effects through the effective incorporation of the following 10 elements: scope of program, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program pursuant to 10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel

Reprocessing Plants." The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining seven elements are evaluated below.

Program Scope: The IST program manages flow blockages of system components from the ECW pump through the ESW and ECW system piping to the emergency cooling tower (ECT). In addition, the program manages heat transfer reduction of the RHR heat exchangers by performing periodic flow testing of the torus water path. The staff finds that relevant piping systems and components are included in the scope of the IST program, and therefore the scope is adequate.

Preventive Action: The applicant stated that IST program consists of condition monitoring activities that detect flow restrictions prior to loss of intended function. No preventive or mitigating attributes are associated with these activities. On the basis of operating experience the staff finds that IST program has been successful in identifying degradation effects and implementing corrective actions. The staff determined that no preventive or mitigating attributes are associated with these activities.

Parameters Monitored or Inspected: The applicant stated that IST program detects flow blockages in ECW and ESW components by measuring ECW pump discharge flow and ESW booster pump discharge flow. The IST program detects heat transfer reduction of the RHR heat exchangers by measuring the flow output of the RHR pump through the associated heat exchanger. The staff concurs with the applicant's determination that the parameters identified for monitoring will permit timely detection of aging effects and, therefore, finds the parameters monitored or inspected acceptable.

Detection of Aging Effects: The applicant stated that IST program activities detect flow blockage and heat transfer reduction aging effects in carbon steel and stainless steel components. The buildup of corrosion products, general silting, and fouling contribute to flow blockage and heat transfer reduction. The test methods, extent, and schedule of the IST program activities provide for detection of flow blockages in the ESW and ECW components and detection of heat transfer reduction in the RHR heat exchangers prior to loss of intended function. The staff agrees that IST program activities should be effective in detecting the aging effect.

Monitoring and Trending: The applicant stated that the periodic testing schedule provides for detection of flow blockage and heat transfer reduction aging effects. Corrective maintenance work orders are initiated for observations of low or inadequate flow. Deficiencies discovered during testing are monitored in accordance with ASME O&M Code requirements. The staff finds the applicant's monitoring and trending method is in accordance with the accepted industry code and, therefore, is acceptable.

Acceptance Criteria: The applicant stated that conditions detected during RHR flow testing are evaluated in accordance with the test procedure by verifying acceptable flow rates through the RHR heat exchangers. ECW system flow, from the ECW pump through the ESW booster pumps to the ECT, is evaluated in accordance with the test procedure by verifying acceptable flow rates at the test point near ETC. The flow testing procedures as described are based on the approved IST program and, therefore, the staff finds the acceptance criteria acceptable.

Operating Experience: The applicant stated that the IST program complies with the ASME O&M Code. The IST program is reviewed and approved by staff every 10 years. The ASME O&M Code incorporates industry practice and experience. The applicant indicated that system modifications have been made to repair and replace piping and components due to leakage and degrading performance. In addition, corrosion, silting, and clams have been discovered and evaluated through plant work order inspections. RHR heat exchanger leaks, degradation of baffle plate welds, and tube plugging events have been noted. Corrective actions were implemented prior to loss of function.

The staff finds that operating experience demonstrates that the containment IST program has been successful in identifying aging effects. The program has been successful in identifying blockage and heat transfer reduction so that intended functions of the components will be maintained consistent with the CLB through the period of extended operation as required by 10 CFR 54.21(a)(3).

3.0.3.10.3 UFSAR Supplement

The staff reviewed Section A.1.11 of the UFSAR Supplement (Appendix A of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

3.0.3.10.4 Conclusions

The staff concludes that the applicant has demonstrated that the aging effects associated with inservice testing (IST) program will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.0.3.11 Maintenance Rule Structural Monitoring Program

The maintenance rule structural monitoring program is described in Section B.1.16 of Appendix B to the LRA. This aging management program is that portion of the applicant's maintenance rule structural monitoring program that is being credited for license renewal. The maintenance rule structural monitoring program provides for condition monitoring of structures and components within the scope of license renewal that are not covered by other inspection programs. The staff reviewed the LRA to determine whether the applicant has demonstrated that the maintenance rule structural monitoring program will adequately manage the aging effects for the components that credit this program throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.11.1 Summary of Technical Information in the Application

Section B.1.16 of the LRA states that the maintenance rule structural monitoring program provides for condition monitoring of reinforced concrete components in the emergency cooling tower exposed to raw water, structural steel components outside primary containment exposed to an outdoor environment, emergency cooling water outdoor piping support anchors, and penetration seals and expansion joint seals.

The aging effects managed by the maintenance rule structural monitoring program are (1) loss of material for carbon steel in an outdoor environment, (2) change in material properties for concrete components exposed to raw water, and (3) cracking, delamination and separation, and change in material properties for seals. The program utilizes inspections to identify aging effects prior to the loss of intended function.

3.0.3.11.2 Staff Evaluation

The staff's evaluation of the maintenance rule structural monitoring program focused on how the applicant demonstrates that the applicable aging effects of the SCs that credit this program will be managed during the period of extended operation. The staff evaluated the maintenance rule structural monitoring program against the following 10 elements: scope of program, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining elements are evaluated below.

Program Scope: Section B.1.16 of the LRA identifies the following specific components that credit the maintenance rule structural monitoring program for managing the identified aging effects, which are enclosed within parentheses:

- emergency cooling tower and reservoir reinforced concrete walls in contact with raw water (change in material properties)
- structural steel components outside primary containment exposed to the outdoor environment, including siding and exterior blowout panels (loss of material)
- emergency cooling water outdoor piping support anchors (loss of material)
- penetration seals and expansion joint seals (cracking, delamination and separation, and change in material properties)

As a result of RAIs 3.5-1 and 3.5-2, several more concrete and structural steel components now credit the maintenance rule structural monitoring program. In response to RAI 3.5-1, the applicant committed to manage loss of material, cracking, and change in material properties for all accessible concrete and masonry block structures. In response to RAI 3.5-2, the applicant committed to manage loss of material for the following carbon steel components:

- structural supports, pipe whip restraints, missile barriers, and radiation shields in the containment structure (Table 3.5-1 of the LRA)
- structural steel components in accessible areas of buildings outside the primary containment (these components and buildings are identified in Tables 3.5-2 through 3.5-12 of the LRA)
- component supports, other than ASME Class 1, 2, or 3 component supports, and anchors for all supports (Table 3.5-13 of the LRA)
- miscellaneous steel components in a sheltered environment (Table 3.5-15 of the LRA)

To be consistent with the commitment made in response to RAIs 3.5-1 and 3.5-2, the applicant needs to clarify that the scope of the maintenance rule structural monitoring program will be revised to include the above concrete and structural steel components, which now credit this program. These additional commitments will require changes to the UFSAR Supplement (Appendix A of the LRA) for the maintenance rule structural monitoring program to add the additional components to the list in the supplement. **This is Confirmatory Item 3.0.3.11.2-1.**

With the addition of the above concrete and structural steel components, response to staff RAIs, the staff finds that the scope of the maintenance rule structural monitoring program is acceptable since it includes a walkdown inspection and aging effects assessment of all structures and components that credit this aging management activity.

Preventive Actions: The applicant identified the condition monitoring as the only inspection activity of the maintenance rule structural monitoring program, and states that no preventive actions are applicable to this aging management program. The staff concurs with this position.

Parameters Monitored or Inspected: Section B.1.16 of the application states that the maintenance rule structural monitoring program provides for a visual inspection of

- emergency cooling tower and reservoir reinforced concrete walls in contact with raw water for evidence of a change in material properties due to leaching of calcium hydroxide
- structural steel components for loss of material
- emergency cooling water outdoor piping support anchors for corrosion
- penetration seals and expansion joint seals for gaps, voids, tears, and general degradation associated with cracking, delamination and separation, and change in material properties

As stated above under Scope of Program, in response to RAI 3.5-1 the applicant committed to manage loss of material, cracking, and change in material properties for all accessible concrete and masonry block structures. To be consistent with this commitment made in response to RAI 3.5-1, the applicant needs to clarify that the parameters inspected for the maintenance rule structural monitoring program will be revised to include inspection of the concrete components, which credit this program, for cracking, loss of material, and change in material properties. **This is part of Open Item 3.0.3.11.2-1.** The additional part of this open item related to the acceptance criteria is discussed below.

For below-grade concrete components, the staff has determined that aging management is unnecessary if applicants are able to show that the below-grade soil/environment is nonaggressive. In RAI B.1.16-1(a), the staff requested that the applicant provide further information regarding the chemistry of the groundwater samples taken at Peach Bottom. In part (b) of RAI B.1.16-1, the staff requested that the applicant describe the provision of the maintenance rule structural monitoring program for inspecting normally inaccessible structures and components. In part (c) of RAI B.1.16-1, the staff requested that the applicant provide the frequency for future groundwater sampling in order to demonstrate that the condition of the below-grade environment for concrete components remains nonaggressive during the period of extended operation. In response to RAI B.16-1, the applicant stated:

(a) Ground and river water (Conowingo pond) samples were tested in January 1968, in preparation for plant construction and recently, July 2000, to support PBAPS AMRs. The range of pH, sulfates and chlorides are as follows:

Period	pH	Sulfates, ppm	Chlorides, ppm
Jan 1968	7.2 - 7.6	10 - 41	14 - 22
Jul 2000	7.2 - 7.3	10 - 38	6 - 24

(b) PBAPS Maintenance Rule Structural Monitoring Program provides for walk-downs and visual inspection of accessible areas. Normally inaccessible structures and components are determined satisfactory based on satisfactory condition of similar accessible structures and components. If findings on accessible structures or components indicated that a potential degradation may be occurring in an inaccessible area, an evaluation will be performed as required by Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." The aging management reviews did not identify unique aging effects for inaccessible structures and components. Thus, inspection of accessible structures and components is representative of both accessible and inaccessible structures and components.

(c) According to NUREG-1557, concrete degradation occurs in an aggressive environment, defined as pH < 5.5, sulfates > 1500 ppm, and chlorides > 500 ppm. PBAPS ground and river water are nonaggressive as indicated by pH, sulfates, and chlorides test results provided in response to item (a) above. Furthermore, the pH, sulfates, and chlorides content of the water are significantly below the threshold limits for aggressive environment. Also, the data reflects over 31 year of operating experience (1968 - 2000) with no significant change in pH, sulfates, or chlorides. Therefore, future continued periodic sampling of ground and river water is not required. The fact that water chemistry has not changed in 31 years provides reasonable assurance that pH, sulfates, and chlorides will remain within nonaggressive limits for concrete through the extended term of operation. As stated in 10 CFR 54.4 Statements of Consideration (SOC), 20 years of operational experience provides substantial amount of information and would disclose any plant-specific concerns with regard to age-related degradation.

The staff concurs with the applicant's approach to inspecting normally inaccessible structures and components as indicated in part (b) above. The use of accessible components of similar material and environment as indicators for aging of inaccessible components is an approach that has been used by previous applicants and has been accepted by the staff. With regard to parts (a) and (c), the staff concurs with the applicant's determination that the present groundwater chemistry is nonaggressive with respect to concrete. Since the pH ranges of (7.2 - 7.6), sulfates (10 - 41 ppm), and chlorides (6 - 24 ppm) are well above or below the levels (pH < 5.5, sulfates > 1500 ppm, chlorides > 500 ppm) at which the soil/groundwater environment would be considered aggressive for concrete components and these values have not changed over a 31-year period of time, the staff concurs with the applicant that periodic monitoring of the groundwater during the period of extended operation is unnecessary.

Detection of Aging Effects: Section B.1.16 of the application states that the aging effects loss of material, change in material properties, cracking, and delamination and separation are detected by visual inspection of external surfaces of the components that credit the maintenance rule structural monitoring program. The staff finds that visual inspections are sufficient to provide reasonable assurance that the aging effects for the components that credit the maintenance rule structural monitoring program will be detected and evaluated before there is a component loss of intended function.

Monitoring and Trending: Section B.1.16 of the application states that structures and components are inspected at least once every 4 years, with provisions to perform trending and root cause analysis and increase the frequency of inspections in the event problems are identified. The staff finds an inspection schedule of at least once every 4 years to be sufficient for the aging management of components that credit the maintenance rule structural monitoring program. Also, the applicant's commitment to do a root cause analysis and increase the frequency of inspection in the event that aging is identified is acceptable to the staff.

Acceptance Criteria: The applicant identified specific acceptance criteria for each of the component groups that credit the maintenance rule structural monitoring program for aging management. These specific acceptance criteria are as follows:

1. Acceptance criteria for the emergency cooling tower and reservoir walls are based on an evaluation of the walls' condition when compared to the condition from previous inspections in order to verify that no changes have occurred that may affect their ability to perform their intended functions.
2. Acceptance criteria for structural steel are directed at finding corrosion that may affect its ability to perform its intended functions.
3. Acceptance criteria for visual inspection of the emergency cooling water outdoor piping support anchors require that structures be free of corrosion that could lead to possible failure.
4. Acceptance criteria for the inspections performed on penetration seals and expansion joint seals are provided on PBAPS drawings and in the inspection procedures for these seals. These documents are directed at finding any changes in the condition of these components that may affect their ability to perform their intended functions.

The above acceptance criteria are adequate to detect the aging of the component groups that originally credited this program; however, as a result of the applicant's response to RAI 3.5-1, several additional concrete components now credit the maintenance rule structural monitoring program. To be consistent with the commitment made in response to RAI 3.5-1, the applicant needs to add additional acceptance criteria for the concrete components which now credit this program. **This is the other part of Open Item 3.0.3.11.2-1.**

In RAI B.1.16-2, the staff requested that the applicant describe the qualifications of the personnel that will be performing the structural monitoring program walkdowns and evaluating the adequacy of the walkdown procedures and findings. In response the applicant stated that the maintenance rule structural monitoring program requires that personnel that perform the walkdowns (inspectors) (1) be qualified evaluators as described below or (2) have received instruction from a qualified evaluator for performance of inspections. For personnel who evaluate the adequacy of the walkdown procedures and findings, the applicant stated that they have (1) a bachelor's degree in civil, structural, or mechanical engineering with 2 years of relevant experience or (2) 5 years of civil/structural experience. The staff considers the above qualifications to be adequate for the performance of the walkdowns and evaluation of the findings associated with the maintenance rule structural monitoring program. Therefore, the applicant's response to RAI B.1.16-2 is considered to be adequate.

Operating Experience: The applicant stated that some specific previous maintenance rule structural monitoring aging management experiences include:

1. Effective management of change in material properties due to contact of the emergency cooling tower and reservoir reinforced concrete walls with raw water by the detection and monitoring of calcium hydroxide.
2. Degraded conditions for some penetration and expansion joint seals. Most of the degradation was not attributed to aging effects.

For each of the above findings, the applicant stated that corrective actions were taken before loss of intended function. Based on the previous and ongoing success of the maintenance rule structural monitoring program in detecting aging of components prior to loss of intended function as well as evaluations of inspection findings, the staff finds that the use of this program during the period of extended operation will provide reasonable assurance that the aging effects for the components that credit this program will be managed such that they continue to perform their intended functions, consistent with the CLB, throughout the period of extended operation.

3.0.3.11.3 UFSAR Supplement

The staff reviewed Section A.1.15 of the UFSAR Supplement (Appendix A of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

3.0.3.11.4 Conclusions

The staff concludes that, with the exception of **Open Item 3.0.3.11.2-1**, the applicant has demonstrated that the aging effects associated with maintenance rule structural monitoring program will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement (Appendix of the LRA), with the exception of **Confirmatory Item 3.0.3.11.2-1**, contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.0.3.12 Ventilation System Inspection and Testing Activities

The applicant's Ventilation System Inspection and Testing Activities program is described in Section B.1.14 of the LRA. This program is credited with managing the potential aging effects of change in material properties in ventilation system components. The staff has reviewed Section B.1.14 of the LRA of the to determine whether the applicant has demonstrated that the effects of aging will be adequately managed by the crane inspection activities during the extended period of operation as required by 10 CFR 54.21(a)(3).

3.0.3.12.1 Technical Information in the Application

Section B.2.3 of the LRA states that PBAPS Ventilation System Inspection and Testing Activities consist of inspections and tests that are relied upon to manage change in material properties in ventilation system components. The Ventilation System Inspection and Testing Activities are implemented through periodic surveillance tests and preventive maintenance work orders that provide for assurance of functionality of the ventilation systems by confirmation of integrity of selected components. The aging management review determined that scope of the components covered by these activities will be enhanced to provide added assurance of aging management.

The applicant concluded that the Ventilation System Inspection and Testing Activities assure that change in material properties is managed for fan flex connections and filter plenum access door seals. Based on the periodic inspection and testing and PBAPS operating experience, there is reasonable assurance that the Ventilation System Inspection and Testing Activities will continue to adequately manage the identified aging effects of the components so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

3.0.3.12.2 Staff Evaluation

The staff's evaluation of the Ventilation System Inspection and Testing Activities focused on how the inspection and testing activities manage the aging effects and ensure the intended function of the affected systems through the effective incorporation of the following 10 elements: scope of program, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative are part of the site-controlled quality assurance program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

Program Scope: The applicant stated that the PBAPS Ventilation System Inspection and Testing Activities include surveillance tests that provide for inspection and leakage testing of the filter plenum access door seals in the standby gas treatment system and the control room ventilation system. These activities also include inspections of fan flex connections for the standby gas treatment system, the control room ventilation system, the battery room and emergency switchgear ventilation system exhaust fans, and the emergency service water booster pump room ventilation supply fans. Ventilation System Inspection and Testing Activities will be enhanced to include inspections of fan flex connections in the diesel generator building ventilation system, the pump structure ventilation system, and the battery room and emergency switchgear ventilation system supply fans. The staff finds that the scope of the program to be acceptable.

Preventive Actions: The applicant stated that Ventilation System Inspection and Testing Activities include the inspections and testing necessary to identify component aging degradation effects prior to loss of intended function. No preventive or mitigative attributes are associated with these activities. The staff considers inspection and testing activities to be a means of detecting, not preventing, aging and therefore agrees that there are no preventive actions required.

Parameters Monitored or Inspected: The applicant stated that the Ventilation System Inspection and Testing Activities monitor and inspect for the presence of aging degradation by visual inspection and leakage testing. Pressure boundary integrity of fan flex connections and filter plenum access door seals is confirmed through inspections for evidence of changes in resilience, strength, and elasticity. Testing of the filter plenum access door seals confirms their leak-tightness. Because the visual inspections and leakage testing are capable of detecting degradation of fan flex connections and filter plenum access door seals, the staff finds that the parameters to be monitored and inspected are acceptable.

Detection of Aging Effects: The applicant stated that Ventilation System Inspection and Testing Activities provide for periodic component inspections and leakage testing to detect change in material properties. The extent and schedule of the inspections and testing assures detection of component degradation prior to the loss of their intended functions. The staff finds that this is an acceptable approach to detect the aging effects.

Monitoring and Trending: The applicant stated that Ventilation System Inspection and Testing Activities provide for monitoring and trending of aging degradation. Ventilation system components are periodically inspected, which provides for timely component degradation detection. The inspection interval is dependent on the component and the system in which it resides. Components in the standby gas treatment system and the control room ventilation system are inspected and tested annually. The applicant further stated, in response to staff RAI 3.3-2, that preventive maintenance (PM) activities for the battery room and emergency switchgear ventilation, control room fresh air supply, emergency service water booster pump room, and diesel generator room are performed every 2 years. PM activities for the pump structure ventilation fans are performed every 4 years. The applicant concluded that, because 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. The staff finds that these monitoring and trending activities are acceptable.

Acceptance Criteria: The applicant stated that Ventilation System Inspection and Testing Activities acceptance criteria are defined in the specific inspection and testing procedures and confirm ventilation system operability by demonstrating that there is no significant pressure boundary leakage. The acceptance criterion for the filter plenum access door seals is lack of visual indication of smoke escaping through the seals during the smoke test. Because the significant pressure boundary leakage and the escaping smoke can be detected, these acceptance criteria are acceptable to the staff.

Operating Experience: The applicant reported that no physical degradation of metallic ventilation system components has been identified at PBAPS or by the industry in general. At PBAPS, the fan flex connection and filter plenum access door seal inspections have detected damaged components that were subsequently replaced in accordance with the inspection procedures. Torn and cracked fan flex connections for various ventilation fans have been detected during performance of inspection procedures. In these cases new flex connections were installed. In addition, access door seal leakage has been detected during performance of the seal leakage testing. New seals were installed as a result of the surveillance test process.

In all cases the corrective actions, including component replacement, were taken prior to loss of intended function.

The staff finds that operating experience demonstrates that the Ventilation System Inspection and Testing Activities program has been successful identifying aging effects and effective at maintaining the intended function of the ventilation systems.

3.0.3.12.3 UFSAR Supplement

The staff reviewed Section A.2.3 of the UFSAR Supplement (Appendix A of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

3.0.3.12.4 Conclusions

The staff concludes that the applicant has demonstrated that the aging effects associated with ventilation system inspection and testing activities will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement (Appendix A of the LRA) contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.0.3.13 Outdoor, Buried, and Submerged Component Inspection Activities

The applicant described the outdoor, buried, and submerged component inspection activities AMP in Section B.2.5 of Appendix B of the LRA. The program provides for management of loss of material and cracking of external surfaces of components subjected to outdoor, buried, and raw water external environments. Separately, the ISI program provides for monitoring of pressure boundary integrity for outdoor and buried components through pressure tests, flow tests, and inspections. The staff reviewed the applicant's description of the AMP in the LRA to determine whether the applicant has demonstrated that the outdoor, buried, and submerged component inspection activities AMP will adequately manage the applicable effects of aging, as discussed above, during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.0.3.13.1 Technical Information in the Application

The outdoor, buried, and submerged component inspection activities are implemented in accordance with PBAPS maintenance procedures and routine test procedures that provide instructions for inspections. Component inspections include inspections of external surfaces for the presence of pitting, corrosion, and other abnormalities. The visual inspections provide reasonable assurance that aging effects are being managed such that system and component intended functions are maintained.

3.0.3.13.2 Staff Evaluation

The staff's evaluation of the outdoor, buried, and submerged component inspection activities focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicates that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

Program Scope: The outdoor, buried, and submerged component inspection activities provide for detection of degradation due to loss of material or cracking of external surfaces for outdoor, buried, and submerged components.

The submerged components include HPSW, ESW, ECW, and fire protection system pumps. Components exposed to the outdoor environment include HPSW and ESW system manual discharge pond isolation valves, condensate storage system piping and valves, the external surfaces of the CSTs, and the piping insulation jacketing at the CST. The buried components include HPSW, ESW, ECW, fire protection, and EDG fuel oil system piping; fire protection system fire main isolation valves; EDG fuel oil storage tanks; the SGTS exhaust to the main stack; and the underside of the CSTs. The scope of these activities will be enhanced to include periodic visual inspection of the external surfaces of the CSTs, periodic visual inspection of the ECW pump casing and casing bolts, and visual inspection of buried commodities whenever they are uncovered during excavation. Inspection of the refueling water storage tank (RWST) will be performed as a representative inspection to determine the condition of the underside of the CSTs. The CSTs and RWST are of same material, construction, and internal environment; thus the condition of the RWST is representative of the condition of the CSTs. The staff found the scope of the program acceptable because the applicant adequately addressed the systems and components whose aging effects could be managed by the application of this activity.

Preventive or Mitigative Actions: The outdoor, buried, and submerged component inspection activities provide inspection methods to identify aging effects on external surfaces prior to loss of intended function. There are no preventive or mitigating attributes associated with these activities, nor did the staff identify a need for such.

Parameters Monitored or Inspected: The outdoor, buried, and submerged component inspection activities provide for inspection of external component surfaces of submerged pumps and outdoor valves for evidence of corrosion and cracking; inspection of buried commodities for the presence of coating degradation, if coated, or base metal corrosion and cracking, if uncoated; inspection of the external surfaces of the CSTs and inspection of outdoor condensate system piping insulation to verify that the jacketing is free of damage; and volumetric inspection of the bottom of the RWST for corrosion as a representative inspection for the underside of the CST. The staff found the parameters monitored or inspected acceptable because these activities support the monitoring and control of these parameters to mitigate loss of material and cracking of the subject components.

Detection of Aging Effects: Outdoor, buried, and submerged components are visually inspected to identify loss of material and cracking aging effects. Outdoor valves are inspected during performance of component maintenance. These inspections provide for detection of external loss of material aging effects. Outdoor insulation jacketing is periodically inspected as part of heat trace testing. The extent and schedule of the outdoor insulation inspections assure detection of loss of material before any jacketing leaks develop.

The excavating procedure will be enhanced to require visual inspection of buried commodities whenever they are uncovered during excavation. The inspection of the external coating, or the base metal if the commodity is uncoated, will detect any external degradation due to aging.

The above ground tank inspection procedure will be enhanced to include periodic visual inspection of the above-ground external surfaces of the CSTs. Inspections during component maintenance of submerged pumps and additional periodic inspections of the ECW pump will detect external casing degradation prior to loss of the pressure boundary function. The staff requested that the applicant address the frequency of inspections of the ECW pump. During a teleconference on August 8, 2002, the applicant indicated that the ECW pumps are inspected every 10 years. **This is part of Confirmatory Item 3.0.3.13.2-1**. The additional part of this item is related to frequency of RWST inspections and is discussed below.

The inspection of the RWST will be enhanced to periodically perform volumetric inspection of the bottom of the RWST for loss of material as a representative inspection to determine the condition of the underside of the CSTs. The staff requested that the applicant address the frequency of inspections of the RWSTs. During a teleconference on August 8, 2002, the applicant indicated that the RWSTS are inspected every 4 years. **This is the other part of Confirmatory Item 3.0.3.13.2-1**.

The staff found that these frequencies of inspections, in combination with other monitoring methods in the PBAPS aging management activities, are adequate to detect the aging degradation in a timely manner prior to loss of intended function.

Monitoring and Trending: Inspections of submerged pumps and outdoor valves are conducted as part of the maintenance process. In addition, the ECW pump will be periodically inspected as part of preventive maintenance. Buried commodities will be visually inspected whenever they are uncovered during excavation activities. The inspections of the RWST will be used to determine the condition of the underside of the CST. Degradation identified during the inspections is evaluated in accordance with procedure requirements. Annual inspections of the outdoor piping insulation jacketing and the above-ground exterior surfaces of the CSTs provide detection of corrosion degradation or damage to the jacketing or to the tanks. The staff found the applicant’s monitoring approach acceptable because the subject program would provide timely detection of aging degradation and sufficient data for trending.

Acceptance Criteria: Identified loss of material or cracking will be evaluated to provide reasonable assurance that system and component functions are maintained. Indications of component degradation detected during the inspection processes will be evaluated by the engineering organization and the adequate corrective actions will be initiated. Degradation of the refueling water storage tank noted during its examination will result in the CSTs being evaluated for degradation. The staff found the acceptance criteria specified by the applicant to be adequate to ensure the intended functions of the systems, structures, and components.

Operating Experience: Significant external surface degradation of outdoor, buried, or submerged components has not been identified to date at PBAPS except for the ECW pump. The performance lives of the HPSW, ESW, and fire protection pumps are limited by wear of the pump internals. Inspections of the casings during maintenance have not detected significant corrosion degradation and the pumps are recoated following reassembly. The ECW pump is operated less frequently. Therefore, its performance life is dependent on external surface degradation. Enhanced periodic inspections of the pump casing and casing bolts will detect future pump casing corrosion degradation. The staff finds the applicant's operating experience to date supports the conclusion that these activities are effective at maintaining the intended function of the systems, structures, and components that may be served by the outdoor, buried, and submerged component inspection activities, and can reasonably be expected to do so for the period of extended operation.

3.0.13.3 UFSAR Supplement

The staff reviewed Section A.2.5 of the UFSAR Supplement (Appendix A of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

3.0.13.4 Conclusions

The staff concludes that, with the exception of Confirmatory Item 3.0.3.13.2-1, the applicant has demonstrated that the aging effects associated with outdoor, buried, and submerged component inspection activities will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement (Appendix A of the LRA) contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.0.3.14 Door Inspection Activities

The applicant described the Door Inspection Activities program in Section B.2.6 of the LRA. The applicant credits this program with managing the potential aging effects of loss of material due to corrosion and change of material properties of gaskets of doors in the scope of license renewal. The staff has reviewed this section of the application to determine whether the applicant has demonstrated that the effects of aging will be adequately managed by the Door Inspection Activities program during the extended period of operation as required by 10 CFR 54.21(a)(3).

3.0.3.14.1 Technical Information in the Application

Section B.2.6 of the LRA characterizes these activities as managing the aging effects for hazard barriers doors that are exposed to the outdoor environment. The applicant's aging management review determined that these activities needed to be enhanced to include (1) additional doors and (2) inspection for loss of material in hazard barrier doors in an outdoor environment. The applicant stated that the door inspection activities provide for managing the aging effects for gaskets associated with water-tight hazard barrier doors in both outdoor and sheltered environments. The inspection activities consist of condition monitoring of the gaskets associated with water-tight hazard barrier doors on a periodic basis in accordance with PBAPS procedures.

In the evaluation and technical basis discussion of Section B.26, the applicant addresses the 10 elements related to the inspection activities. They are discussed in Section 3.0.3.14.2 of this SER.

In summary, the applicant stated: “Based on the PBAPS operating experience there is reasonable assurance that the door inspection activities will continue to adequately manage the aging effects on hazard barrier doors in an outdoor environment and on gaskets associated with water-tight hazard barrier doors in outdoor and in sheltered environments so that the intended functions will be maintained consistent with the CLB for the period of extended operation.”

3.0.3.14.2 Staff Evaluation

The staff evaluation of the Door Inspection Activities program focused on how the activities managed aging effects through the effective incorporation of the following 10 elements: scope of program, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff’s evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

Though the applicant does not provide cross-references to the aging management review with which these activities are associated, the staff’s review of the LRA indicates that these activities are associated with Section 3.5.14 of the LRA.

Program Scope: The door inspection activities provide for inspections and evaluations of hazard barrier doors exposed to the outdoor environment and of gaskets for water-tight hazard barrier doors exposed to the outdoor and sheltered environments. The PBAPS procedures governing the inspections will be enhanced to identify additional doors and to include more inspection parameters linked to loss of material in hazard barrier doors in an outdoor environment.

The applicant excluded the inspection for loss of material for structural components of the doors in the sheltered environment. As the doors are located in various structures and appurtenances, and the ambient environment in the sheltered areas may not be always benign, the LRA does not provide a clear basis for excluding loss of material for structural components in the sheltered environment. The staff requested further information concerning this issue in RAI B.2.6-1. The applicant responded in letter dated April 29, 2002, that it had revised the door inspection activity to include monitoring of hazard barrier doors in a sheltered environment for loss of material due to corrosion. The staff finds the response adequate and the program scope acceptable.

Preventive Actions: The hazard barrier doors inspection activities are condition monitoring activities that utilize inspections to identify aging effects prior to loss of intended function. There are no preventive or mitigating attributes associated with this activity. The staff agrees with the applicant's statement regarding the preventive actions.

Parameters Monitored or Inspected: Hazard barrier doors exposed to the outdoor environment are and will be inspected for evidence of loss of material due to corrosion. Gaskets associated with water-tight hazard barrier doors in an outdoor environment are inspected to detect change in material properties. Gaskets for water-tight hazard barrier doors in a sheltered environment are inspected for evidence of change in material properties and cracking.

The program will monitor the loss of material of carbon steel doors and degradation and change in properties of seals and gaskets associated with the doors. However, it does not address the operating attributes of the doors, such as hinges and latches, and the operating mechanism of the door. The staff requested information regarding these components in RAI B.2.6-2. The applicant responded in a letter dated April 29, 2002, that door hinges, latches, and operating mechanisms are active components and are not subject to aging management review. The staff agrees that hinges and latches are excluded from management reviews in accordance with 10 CFR 54.21(a)(1). The staff finds the parameters monitored or inspected element acceptable.

Detection of Aging Effects: Inspections for loss of material of water-tight hazard barrier doors and inspections of associated gaskets for change in material properties and cracking are performed and results are documented. Inspections for loss of material of other hazard barrier doors exposed to the outside environment will be performed and the results documented.

The detection of change in material properties cannot be assessed by visual inspection. The staff requested information regarding the method of detecting this aging effect on seals and gaskets in RAI B.2.6-3. The applicant responded in a letter dated April 29, 2002, and provided the following answer:

> Door inspection activities 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.

The staff considered the response acceptable because a visual inspection will provide an indication of the gasket's physical condition. The staff considers the program element detection of aging effects acceptable.

Monitoring and Trending: The door inspection activities periodically monitor water-tight hazard barrier doors for loss of material due to corrosion and their gaskets for change in material properties and cracking. In addition, door inspection activities will periodically monitor other hazard barrier doors for loss of material due to corrosion.

The effectiveness of the program in detecting the aging effects depends upon the frequency of inspections. RAI B.2.6-4 requested this information. The applicant provided the following response in letter dated April 29, 2002:

> Door inspection activities are performed on a frequency of 4 years or less. The frequency is consistent with the frequency of PBAPS Maintenance Rule Structural Monitoring Program (B.1.16) and industry practices for implementing the requirements of 10 CFR 50.65 for structures. The frequency is selected to ensure, with reasonable assurance, that aging degradation of hazard barrier doors will be detected before there is a loss of intended functions."

The staff finds the response adequate because the PBAPS Maintenance Rule Structural Monitoring Program will monitor the condition of hazard barrier doors.

Acceptance Criteria: Acceptance criteria for hazard barrier doors and gaskets associated with water-tight hazard barrier doors are provided in PBAPS procedures. If an indication or evidence of a degraded condition is found, the information is forwarded to engineering for evaluation to determine if an unacceptable visual indication of loss of material, cracking, or change in material properties exists. The staff considers these generic acceptance criteria adequate for detecting the aging effects.

Operating Experience: A review of the operating experience for hazard barrier doors and gaskets associated with water-tight hazard barrier doors found no degraded conditions due to loss of material, change in material properties, or cracking that resulted in loss of intended function. Corrosion on hazard barrier doors was found in a few instances, mainly on those doors with one face exposed to an outdoor environment. This condition was typically due to drainage problems that allowed the water to run toward the door rather than away from it. Corrective actions were taken to eliminate the drainage problem and door degradation prior to loss of intended function. There were a few instances of water-tight door gasket replacements. The cause, in most cases, was manmade. Plant documentation cited a few instances of debris within the gasket folds preventing door closure. Debris was removed and gaskets inspected with no detrimental effects observed. The staff finds that the operating experience indicates that the applicant's door inspection and maintenance activities will provide reasonable assurance that the intended function of the doors will be maintained.

3.0.3.14.3 UFSAR Supplement

The staff reviewed Section A.2.6 of the UFSAR Supplement (Appendix A of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

The summary description of the door inspection program provided in Section A.2.6 of Appendix A to the LRA does not reflect the additional commitment made by the applicant to include monitoring of hazard barrier doors in a sheltered environment for loss of material due to corrosion. **This is Confirmatory Item 3.0.3.14.3-1.**

3.0.3.14.4 Conclusions

The staff concludes that the applicant has demonstrated that the aging effects associated with door inspection activities will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that, with the exception of Confirmatory Item 3.0.3.14.3-1, the UFSAR Supplement (Appendix A of the LRA) contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.0.3.15 Generic Letter 89-13 Activities

The applicant described the Generic Letter (GL) 89-13 activities AMP in Section B.2.8 of Appendix B of the LRA. The staff reviewed the applicant's description of the AMP in the LRA to determine whether the applicant has demonstrated that the GL 89-13 activities AMP will adequately manage the applicable effects of aging of systems and components exposed to raw water during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.0.3.15.1 Technical Information in the Application

In Section B2.8 of the LRA, the applicant identified the GL 89-13 activities AMP as an enhanced AMP that will be used by the applicant to manage loss of material and cracking of piping, piping specialities (flow element, strainer screens, and orifice), pump casings, and valve bodies in the high-pressure service water (HPSW), emergency service water (ESW), and emergency cooling water (ECW) systems together with the ISI activities AMP (as discussed in Section B.1.8 of the LRA). The AMP by itself will be used to manage flow blockage and heat transfer reduction of the systems and components mentioned above. The AMP by itself will also be used to manage the aging effects of the RHR heat exchangers, HPSW; and core spray (CS) pump motor oil coolers; high-pressure cooling isolation (HPCI), reactor core cooling isolation (RCIC), and RHR pump room cooling coils; and emergency diesel generator (EDG) jacket, air, and lube oil coolers exposed to raw water.

The Generic Letter (GL) 89-13 activities AMP consists of system and component testing and biocide treatments in accordance with the guidelines of NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment." This AMP will be enhanced to require visual inspections to detect specific signs of degradation, including corrosion, cracking, excessive wear, and Asiatic clams and ultrasonic testing (UT) to detect wall thinning at susceptible piping locations.

3.0.3.15.2 Staff Evaluation

The staff's evaluation of the Generic Letter (GL) 89-13 activities focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicates that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

Program Scope: The applicant stated that the AMP manages loss of material, cracking, flow blockage, and heat transfer reduction in the systems and components exposed to raw water. These systems and components include piping, piping specialities (flow element, strainer screens, and orifice), pump casings, and valve bodies in the HPSW, ESW, and ECW systems. This AMP also covers the RHR heat exchangers, HPSW and CS pump motor oil coolers, HPCI, RCIC, and RHR pump room cooling coils, and EDG jacket, air, and lube oil coolers exposed to raw water. The staff found the scope of the program to be acceptable because the applicant adequately addressed the systems and components whose aging effects could be managed by the application of this program.

Preventive or Mitigative Actions: The applicant stated that the GL 89-13 activities AMP provides for periodic biocide treatments and flushing of infrequently used systems to mitigate corrosion and flow blockage aging effects due to biofouling. The staff found the preventive and mitigative actions acceptable because these actions would mitigate or prevent aging degradation of loss of material, cracking, flow blockage, and heat transfer reduction in the systems and components exposed to raw water.

Parameters Monitored or Inspected: The applicant stated that this AMP provides system and component testing for monitoring flow rate, pressure, and heat removal rate. The GL 89-13 activities AMP will also provide for visual inspections for corrosion, cracking, and silting to identify loss of material, flow blockage and heat transfer reduction and UT examination of piping for wall thinning.

The staff believes that the inspection of external protective coatings in the systems such as HPSW and ESW that contain raw water should be covered in the AMP. Therefore, in RAI B2.8-2, the staff requested the applicant to address the basis for not including the inspection of the external protective coatings of the HPSW and ESW systems in the AMP.

In a letter dated May 14, 2002, the applicant stated that the Generic Letter 89-13 activities AMP does not include inspection of external protective coatings. External protective coating inspections for components susceptible to external surface aging effects are included in the outdoor, buried, and submerged component inspection activities AMP (as discussed in Section B.2.5 of the LRA). The outdoor, buried and submerged component inspection activities AMP is referenced in Table 3.3-5 of the LRA for HPSW system piping, valve bodies, and pump casings. The outdoor, buried, and submerged component inspection activities AMP is referenced in Table 3.3-6 of the LRA for ESW system piping, valve bodies, and pump casings. The outdoor, buried, and submerged component inspection activities AMP is referenced in Table 3.3-7 of the LRA for the fire protection system piping, valve bodies and pump casings. The outdoor, buried and submerged component inspection aging management activity, as described in Section B.2.5 of the LRA, includes inspections of external surfaces for loss of material and cracking. Buried components are inspected for coating degradation, if coated. Based on the applicant's response to the staff and the information in the LRA, the staff found the Generic Letter 89-13 activities program to be capable of detecting the aging effects associated with the systems and components exposed to raw water.

Detection of Aging Effects: The applicant stated that aging effects of loss of material and cracking are detected through component visual inspection. Wall thinning due to loss of material in piping is detected through UT. Aging effects of flow blockage and heat transfer reduction are detected using a combination of system and component performance testing and component visual inspection during disassembly. The staff found the inspection techniques to be adequate for detection of aging effects of loss of material, cracking, flow blockage, and heat transfer reduction prior to loss of component intended function.

Monitoring and Trending: The applicant stated that system and component performance testing, piping UT, and periodic component visual inspections provide for timely detection of aging effects of loss of material, cracking, flow blockage, and heat transfer reduction. Pumps and valves are visually inspected for loss of material, cracking, and flow blockage during component maintenance. Performance and flow tests of heat exchangers are conducted from once every 6 weeks to once every 48 months. Biocide treatment of the ESW and HPSW systems as done once every 6 months. The staff found the applicant's approach to monitoring activities to be acceptable because it is based on methods that are sufficient to predict the extent of degradation so that timely corrective or mitigative actions are possible.

Acceptance Criteria: The applicant stated that engineering evaluations of identified aging degradation, including loss of material, cracking, and flow blockage, are performed to confirm the component's ability to perform its intended function. Semiannual biocide injection into the ESW and HPSW systems is performed per chemistry guidelines regarding concentration and treatment durations. Flow rates and heat removal rates measured from the heat exchanger test are compared with the system requirements specified in the plant procedures. The staff found the acceptance criteria acceptable because they are contained in the chemistry guidelines and plant procedures and are directly relevant to the conditions of the systems and components.

Operating Experience: The applicant stated that prior to the implementation of GL 89-13, corrosion-induced leakage and reduced system performance had occurred primarily in the ESW system. The GL 89-13 inspection activities AMP has detected the presence of corrosion, silting, and clams. Corrective actions were implemented by the applicant. The staff found that the operating experience has been satisfactorily incorporated into the development of this AMP. The GL 89-13 inspection activities AMP has been effective in managing the aging effects and is adequate to detect the aging degradation in timely manner prior to loss of component intended function.

3.0.3.15.3 UFSAR Supplement

The staff reviewed Section A.2.8 of the UFSAR Supplement (Appendix A of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

3.0.3.15.4 Conclusions

The staff concludes that the applicant has demonstrated that the aging effects associated with Generic Letter 89-13 inspection activities will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR

54.21(a)(3). The staff also concludes that the UFSAR Supplement (Appendix A of the LRA) contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.0.3.16 Fire Protection Activities

3.0.3.16.1 Technical Information in the Application

The applicant described the Fire Protection Activities program in Section B.2.9 of Appendix B to the LRA. The applicant credits the testing under this program with managing the effects of aging of the fire protection system. The staff has reviewed Section B.1.11 of the LRA to determine whether the applicant has demonstrated that the effects of aging will be adequately managed by the IST program during the extended period of operation as required by 10 CFR 54.21(a)(3).

The purpose of the Fire Protection Activities program is to manage loss of material and fouling of specific components exposed to raw water within the scope of license renewal in the fire protection systems. These activities manage loss of material in sprinklers, which can affect the pressure boundary and spray functions of the sprinklers. These activities also manage fouling of sprinklers, valves at hydrants, and valves at hose racks; fouling can affect the component function. These activities constitute a condition monitoring program that is credited with managing the subject aging effect for brass and bronze materials exposed to a raw water environment.

Fouling is considered an aging effect requiring management for the fire protection systems because of operating experience at Peach Bottom. For the purpose of license renewal, fouling is applicable to the distribution components (sprinklers, hose station valves, and hydrant valves) of the fire protection systems. As indicated by the description of this program, managing fouling of the distribution components ensures that the system is capable of performing its function of supplying fire suppression water through the distribution components. In addition, a one-time test will be conducted to detect loss of material due to selective leaching.

The fire protection activities are designed to protect plant equipment in the event of a fire, to ensure safe plant shutdown, and to minimize the risk of a radioactive release to the environment. The fire protection system relies on fire water supply, including sprinklers, Halon suppression, fire dampers, RCA oil collection, alternate shutdown, safe shutdown, and fire detection and protection. Individual components relied upon for alternate shutdown and safe shutdown were screened with their respective systems. The screening for fire detection and protection electrical and instrumentation and controls is discussed in Section 2.5 of the LRA.

Fire protection components that are subject to an aging management review include the raw water tanks, pumps and valves (pressure boundary only), tanks, heat exchangers, hose stations, flame arrestors, sprinklers, strainers, orifices, piping, tubing, and fittings. The intended functions for fire protection components that are subject to an aging management review are pressure boundary integrity, heat transfer, filtration, throttling, fire spread prevention, and spray. A complete list of the fire protection components that require aging management review appears in Table 3.3.7 of the application. Fire extinguishers, fire hoses, and air packs are not subject to an aging management review because they are replaced based on condition in accordance with National Fire Protection Association (NFPA) standards and plant surveillance procedures for fire protection equipment.

3.0.3.16.2 Staff Evaluation

The staff's evaluation of the fire protection inspection activities program focused on how the program manages the aging effect through the effective incorporation of the following 10 elements: program scope, preventive or mitigative actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining seven elements are evaluated below.

Program Scope: The components within the scope of the Fire Protection Activities program are the sprinklers and fire hydrant valves and hose rack valves of the interior fire protection system and the exterior fire protection system. These components include the diesel-driven fire pump fuel oil system pumps, valves, piping and tubing, buried fire main piping and valves, outdoor fire hydrants, hose connections and hose station block valves, and fire barrier penetration seals, fire barrier doors, and fire wraps exposed to sheltered and outdoor environments.

The scope of fire protection activities will be enhanced to—

- Require additional inspection requirements for deluge valves in the power block sprinkler systems.
- Perform functional tests of sprinkler heads that have been in service for 50 years.
- Inspect diesel-driven fire pump exhaust systems.
- Inspect diesel-driven fire pump fuel oil system flexible hoses.
- Inspect fire doors for loss of material.
- Perform a one-time test of a cast iron fire protection component.

The staff finds acceptable the scope of the components and systems within fire protection activities, including the enhancements.

Preventive Actions: The fire protection activities provide system monitoring, performance testing, and inspections to identify aging effects prior to loss of intended function. There are no preventive or mitigating actions associated with these activities, and the staff did not identify the need for any.

Parameters Monitored or Inspected: The existing fire protection activities provide for visual inspections and/or monitoring of the fire protection piping, sprinklers, and valves:

- To detect loss of material, cracking and flow blockage.
- Visual inspection of fire pumps for loss of material and flow blockage during corrective maintenance activities.
- Visual inspections of the diesel-driven fire pump fuel oil system pumps, valves, piping, and tubing to detect loss of material and cracking.

- Monitoring of fire protection system pressure to detect leakage of buried fire main piping and valves.
- Flow tests to detect fire protection system blockage and component degradation in buried fire main piping and valves, outdoor fire hydrants, hose connections, and hose station block valves.
- Visual inspections of fire barrier penetration seals, fire barrier doors, and fire wraps to detect changes in material properties, cracking, delamination, separation, and loss of material.

Fire protection activities will be enhanced to include:

- Power block deluge valve visual inspection requirements to include examinations for loss of material, cracking, and flow blockage.
- Functional testing for flow blockage of sprinkler heads that have been in service for 50 years.
- Visual inspections to detect loss of material of the diesel-driven fire pump exhaust system.
- Visual inspections to detect a change in material properties of the diesel-driven fire pump fuel oil system flexible hoses.
- Visual inspections of fire doors for loss of material.
- Testing of a cast iron fire protection component to detect loss of material due to selective leaching.

In RAI B 2.9-1, the staff asked the applicant to discuss its inspection plans for the sprinkler heads at Peach Bottom during the current licensing term as well as during the period of extended operation. In its response, the applicant stated that testing will comply with the frequency requirements of NFPA-25, Section 2-3.1. However, for Peach Bottom, the applicant will perform the test only twice. Peach Bottom received the construction permit on January 31, 1968; therefore, the earliest that the first sprinkler test is required is 2018, and the next sprinkler test is required in 2028. Unless another 20 year extension is proposed, there will not be a third test. The staff finds the applicant's response acceptable because the applicant will perform two sprinkler inspections which is consistent with the staff's interim staff guidance position (ISG), ISG-4 (Letter to Mr. Alan Nelson of NEI dated January 28.2002).

The staff noted that the applicant is committing to inspect the diesel-driven fire pump flexible hoses, but has not provided the kind of details regarding the inspection activities that were provided for the EDG fuel oil system flexible hoses. Therefore, the staff cannot conclude that the inspection activities for the diesel-driven fire pump fuel oil system flexible hoses provide adequate aging management. The applicant needs to provide information for the fire oil pump fuel oil flexible hoses comparable to that provided for the EDG flexible hoses. **This is part of Open Item 3.0.3.16.2-1.** Additional parts of this open item are discussed below under detection of aging effects, monitoring and trending, and acceptance criteria.

The staff finds that the parameters monitored as discussed above will permit timely detection of the aging effects and are, therefore, acceptable, with the exception of the open item discussed above.

Detection of Aging Effects: The existing fire protection activities provide for—

- Periodic visual inspections of the fire protection system piping, sprinklers, and valves that will detect loss of material, cracking, and flow blockage prior to loss of intended function.
- Visual inspection of fire pumps for loss of material and flow blockage during corrective maintenance activities.
- Periodic visual inspections of the diesel-driven fire pump fuel oil system pumps, valves, piping, and tubing that will detect loss of material and cracking prior to loss of intended function.
- Continuous monitoring of fire protection system pressure that will detect pressure boundary leakage of buried fire main piping and valves prior to loss of intended function.
- Periodic flow tests that will detect fire protection system blockage and components degradation in buried fire main piping and valves, outdoor fire hydrants, hose connections, and hose station block valves prior to loss of intended function.
- Periodic visual inspections of fire barriers that will detect loss of material in fire doors and changes in material properties, cracking, delamination, separation, and loss of material in fire barrier penetrations and fire wraps prior to loss of intended functions.

Fire protection activities will be enhanced to include—

- Periodic visual inspection of power block deluge valves to detect loss of material, cracking and flow blockage prior to loss of intended function.
- Functional testing of sprinkler heads that have been in service for 50 years to detect flow blockage.
- Periodic visual inspections of the diesel-driven fire pump exhaust system to detect loss of material prior to loss of intended function.
- Visual inspections of the diesel-driven fire pump fuel oil system flexible hoses to detect a change in material properties prior to loss of intended function.
- Added specificity for detection of loss of material in requirements for visual inspection of fire doors.
- A one-time test of cast iron fire protection component to detect loss of material due to selective leaching.

In RAI B 2.9-2, the staff asked the applicant to describe the tests and inspections to detect the degradation of the fuel supply line. In its response, the applicant stated that visual inspections of the diesel-driven fire pump, fuel oil system pumps, valves, piping, and tubing are performed to detect loss of material and cracking. In addition, fuel oil testing activities provide for sampling and testing of fuel oil as a preventive action. These activities are discussed in LRA Appendix B.2.1, “Lubricating and Fuel Oil Quality Testing Activities.” The staff finds these inspections and tests satisfactory for detection of degradation of the fuel supply line.

In RAI B 2.9-3, the staff asked the applicant to discuss the internal inspections of the fire protection piping to detect wall thinning due to internal corrosion. In its response, the applicant stated that only visual inspections are performed for fire protection system components to detect loss of material. Also, fire main pressure is continuously monitored for leakage. Fire main flow testing and hydrant flushes and inspections are performed on a periodic basis. The wet sprinkler piping will be flow tested in accordance with procedures discussed in the applicant's response to RAI 3.3-8, as described below. The staff requires that portions of the fire protection suppression piping that are exposed to water be evaluated for wall thickness. By letter dated July 29,2002, the applicant revised the inspection program to include volumetric examination of the fire protection piping at vulnerable locations in order to evaluate wall thickness and detect loss of material. With this revision, the inspections of fire protection piping to detect wall thinning due to internal corrosion are consistent with the interim staff guidance position, ISG-4 (Letter to Mr. Alan Nelson of NEI dated January 28.2002). Therefore, the staff finds the inspections reasonable and acceptable.

In RAI B 2.9-4, the staff asked the applicant to discuss the inspection activities at Peach Bottom to provide the reasonable assurance that the intended function of below-grade fire protection piping will be maintained consistent with the CLB for the period of extended operation. In its response, the applicant stated that the existing fire protection system activities provide for monitoring of fire protection system pressure to detect pressure boundary leakage of buried fire main piping and flow tests to detect fire protection system blockage and component degradation in buried fire main piping. Additionally, LRA Appendix B 2.5 indicates that the excavating procedure will be enhanced to require visual inspection of buried commodities whenever they are uncovered during excavation. The scope of this aging management activity includes buried commodities in fire protection system. The applicant inspected two buried piping sections in 2001. For these sections, the internal and external coating was good. One section was tested for selective leaching. The results showed no evidence of selective leaching. These sections have been in operation for 25-30 years. Based on a review of the applicants inspection and test results, as well as operational experience, as discussed above, the staff finds that the existing fire protection system activities will manage degradation of the buried fire main piping.

The staff finds that the detection of aging effects as discussed above is acceptable with the exception of the visual inspection of the diesel-driven fire pump fuel oil system flexible hoses. **This is part of Open Item 3.0.3.16.2-1.**

Monitoring and Trending: Existing fire protection activities provide for the following monitoring and trending activities:

- Sprinkler systems are functionally tested for flow blockage on a periodic basis.
- Fire main flow testing, and hydrant flushes and inspections, are performed on a periodic basis.
- The diesel-driven fire pump fuel oil system is visually examined for loss of material and cracking on a periodic basis.
- Fire main pressure is continuously monitored for leakage.
- Specified sample quantities of fire barrier penetration seals are inspected every 24 months with the entire population being inspected every 16 years for change in material properties, cracking, delamination, and separation.
- Fire wraps on structural steel and on electrical raceways are periodically visually inspected for change in material properties and loss of material.

Enhancements to fire protection activities will provide for the following monitoring and trending activities:

- Sprinkler system deluge control valves will be visually inspected for loss of material, cracking, and flow blockage following sprinkler system testing.
- A representative sample of sprinkler heads that have been in service for 50 years will be functionally tested for flow blockage and verification of proper operation.
- The diesel-driven fire pump exhaust system will be visually inspected for loss of material on a periodic basis.
- Diesel-driven fire pump fuel oil system flexible hoses will be visually examined for a change in material properties on a periodic basis.
- Fire barrier doors will be visually inspected for loss of material on a periodic basis.
- If the one-time test yields unfavorable results, the scope will be expanded to other components, based upon engineering evaluations.

Fire protection testing and inspections are performed in accordance with controlled plant procedures. Any degradation identified during testing and component inspections is evaluated in accordance with procedural requirements. When applicable, trending of findings is performed to determine potential long-term impact.

In RAI 3.5-8, the staff asked the applicant to identify how the internal condition of this piping will be verified to assure flow capability. By letter dated May 6, 2002, the applicant responded that fouling of the pipe internals is addressed in the LRA 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. The applicant stated the following:

> 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.

The sprinkler system testing performed at PBAPS is similar to the testing that has been reviewed and approved for other plants, such as Hatch. The staff finds the flow test acceptable becauseit will assure flow capability.

The staff finds that the applicant’s methodology will provide effective monitoring and trending of the aging effects and is therefore acceptable with the exception of the frequency of the visual inspections of the diesel-driven fire pump fuel oil system flexible hoses. **This is part of Open Item 3.0.3.16.2-1.**

Acceptance Criteria: Tests and inspections for flow blockage, loss of material, cracking, change in material properties, and cracking, delamination, and separation aging effects are conducted in accordance with plant procedures. These procedures contain specific acceptance criteria to confirm the system's ability to maintain required system pressures and flow rates and specific acceptance criteria for components and fire barriers to confirm their functionality. The diesel-driven fire pump engine manufacturer's representative is present during engine inspections and provides standards to ensure that inspections are properly performed and that the material condition of the exhaust and fuel oil system components is acceptable.

Acceptance criteria for fire barrier doors require that there be no visual indication of corrosion. Acceptance criteria for fire barrier penetrations seals and fire wraps require that they exhibit no change in material properties, cracking, delamination, separation, and loss of material. The acceptance criteria take the component material specification into account.

In RAI 3.3-9, the staff asked the applicant to provide the acceptance criteria which would identify unacceptable changes in material properties and the bases for these criteria. In its response dated May 6, 2002, the applicant stated the following:

> Change in material properties aging effect is specified in Table 3.5-14 of the LRA for materials, which are used for the following component groups:
>
> - Fire Barrier Penetration Seals
> - Other Hazard Barrier Penetration Seals
> - Gaskets for watertight doors
> - FireWraps
> - 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 V4" 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 14"
>   - Verify that shrinkage of seal away from penetration surface (concrete or embedded sleeve) is less than 118" and no deeper than ¾"

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 Y2"
- Verify shrinkage of the grout away from the penetration surface is less than 1/8" and no deeper than Y2"
- 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-96-1 46, '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.

The staff finds these criteria reasonable and acceptable because they will provide an effective means of detecting changes in material properties such that the effects of aging will be detected and evaluated before failure would occur with the exception of the acceptance criteria for the visual inspection of the diesel-driven fire pump fuel oil system flexible hoses. **This is part of Open Item 3.0.3.16.2-1.**

Operating Experience: Buried cast iron components have typically demonstrated reliable performance in commercial and industrial applications for long operational periods. At Peach Bottom, repairs and replacements of several hydrants, fire pumps, and indoor piping have been required due to internal corrosion and wear. The presence of corrosion, silting, and clams have been noted during plant work order inspections. Modifications and work orders have repaired and replaced degraded fire barrier penetrations and fire barrier doors. Corrective actions were implemented prior to loss of system or barrier functions. The diesel-driven fire pump fuel oil system has experienced minor leakage events that were detected and corrected in a timely manner. There have been no age-related component failures resulting in a loss of function for the components covered by this aging management activity. The staff finds that, based on the operating experience at Peach Bottom, there is reasonable assurance that the aging of the fire protection components will be managed adequately so that the structure and component intended functions will be maintained during the extended period of operation.

3.0.3.16.3 UFSAR Supplement

The staff reviewed Section A.1.9 of the UFSAR Supplement (Appendix A of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

3.0.3.16.4 Conclusions

The staff concludes that, with the exception of **Open Item 3.0.3.16.2-1**, the applicant has demonstrated that the aging effects associated with fire protection activities will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement (Appendix A of the LRA) contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.0.3.17 Heat Exchanger Inspection Activities

The applicant described the heat exchanger inspection activities AMP in Section B.2.12 of Appendix B of the LRA. The staff reviewed the applicant’s description of the AMP in the LRA to determine whether the applicant has demonstrated that the heat exchanger inspection activities AMP will adequately manage the effects of aging caused by components exposed to condensate storage water during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.0.3.17.1 Technical Information in the Application

The applicant stated that the heat exchanger inspection activities provide for periodic component visual inspections and component cleaning of heat exchangers and coolers that are outside the scope of NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-related Equipment." The applicable components of this AMP are in the engineered safety featured systems (high-pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC)). The heat exchanger inspection activities AMP, either by itself or in conjunction with the condensate storage tank chemistry AMP (as discussed in Section B.1.4 of the LRA), is used at PBAPS to manage loss of material, cracking, and heat transfer reduction in components that contain or are exposed to condensate storage water.

The applicant further stated that the aging management review determined that the aging management of loss of material and cracking of the HPCI gland seal condenser will be enhanced by periodic inspections of the HPCI gland seal condenser tube side internals. The aging management activities include condition monitoring for managing loss of material, cracking, and heat transfer reduction effects for heat exchangers and coolers in a reactor-grade water environment. The applicant concluded that based on PBAPS operating experience, there is reasonable assurance that the heat exchanger inspection activities will continue to manage loss of material, cracking, and heat transfer reduction for heat exchangers and coolers in a reactor-grade water environment so that the intended functions are maintained consistent with the CLB for the period of extended operation.

3.0.3.17.2 Staff Evaluation

The staff's evaluation of the heat exchanger inspection activities focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicates that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

Program Scope: The heat exchanger inspection activities provide for aging management for the HPCI gland seal condenser, the HPCI turbine lube oil cooler, and the RCIC turbine lube oil cooler through the cleaning and inspection of the heat exchangers on the water side. The applicant further stated that the scope of the activities would be enhanced to include periodic inspection of the HPCI gland seal condenser tube side internals. The staff requested that the applicant indicate what percentage of the subject heat exchangers are inspected. During a teleconference on August 6, 2002, the applicant indicated that all tubes of the HPCI gland seal condenser and the HPCI turbine lube oil cooler heat exchangers are visually inspected. **This is**

part of Confirmatory Item 3.0.3.17.2-1. The additional part of the confirmatory item is discussed below under the acceptance criteria program element.

The staff found the scope of the program to be acceptable because the applicant adequately addressed the components whose aging effects could be managed by this activity.

Preventive or Mitigative Actions: The applicant stated that the heat exchanger inspection activities detect loss of material, cracking, and heat transfer reduction aging effects prior to loss of intended function. The applicant indicated that there are no preventive or mitigating attributes associated with these activities. The staff considers inspection activities a means of detecting, not preventing, aging and, therefore, agrees that there are no preventive actions associated with the heat exchanger inspection activities.

Parameters Monitored or Inspected: The applicant stated that the heat exchanger visual inspections are performed in accordance with PBAPS procedures to identify degradation associated with loss of material, cracking, and heat transfer reduction aging effects. The staff requested additional information from the applicant to provide a more detailed description of the PBAPS inspection procedures in regard to methodology, frequency of inspections, and parameters inspected/monitored. The applicant responded, in a letter to the NRC dated May 14, 2002, that the heat exchangers are opened and visually inspected for degradation due to loss of material, cracking, and heat transfer reduction. They are cleaned and reassembled. A post-maintenance test verifies operability. The component inspections are scheduled as part of the HPCI and RCIC turbine maintenance which is performed every 8 years. The staff found the applicant's approach to be capable of adequately detecting the applicable aging effects using the heat exchanger inspection activities.

Detection of Aging Effects: The applicant stated that loss of material and cracking degradation are detected through component surface visual inspections of the HPCI and RCIC turbine lube oil coolers on the water side. The applicant further stated that the existing maintenance procedures for the HPCI gland seal condenser would be enhanced to include periodic inspections of the condenser tube side internals to provide assurance of aging management for loss of material and cracking of the HPCI gland seal condenser. During disassembly, visual inspection for fouling would identify conditions, which could result in heat transfer reduction.

Section A1.2.3.4, "Detection of Aging Effects," of NUREG-1800 (July 2001) states that a justification needs to be provided as to whether the techniques are adequate to detect aging effects before a loss of SC intended function. The LRA indicates that loss of material and cracking are detected through component surface visual inspections of the HPCI and RCIC turbine lube oil coolers on the water side. Therefore, the staff requested additional information from the applicant concerning the levels (e.g., VT-1) at which the visual inspection would be conducted. In addition, the staff finds that the identified visual defects need further investigation, including NDE examinations if adequate.

The applicant responded, in a letter to the NRC dated May 14, 2002, that the visual inspections are performed by qualified maintenance technicians in accordance with inspection procedures. There is no VT requirement in the procedures. Maintenance supervision is notified of any abnormal as-found conditions. If the as-found conditions are outside of the expected condition, an evaluation is performed to determine the adequate corrective action. The applicant further stated that part of the evaluation may include NDE examinations, as warranted. The staff found the description of the detection of aging effects reasonable and therefore acceptable.

Monitoring and Trending: The applicant stated that the periodic component visual inspections and cleaning are conducted as part of HPCI and RCIC turbine inspections, and provide for timely detection of loss of material, cracking, and heat transfer reduction prior to loss of intended function. Section A.1.2.3.5 of NUREG-1800 states that it is necessary to confirm that the next scheduled inspection will occur before a loss of SC intended function. Therefore, the staff requested additional information from the applicant concerning the schedule for the periodic component visual inspections and cleaning as part of the HPCI and RCIC turbine inspections and the justification for the inspection interval.

The applicant responded, in a letter to the NRC dated May 14, 2002, that the HPCI and RCIC turbine maintenance is performed every 8 years and this frequency is based on plant-specific operating and maintenance experience with the HPCI and RCIC turbines. The component inspections are scheduled as part of the turbine maintenance. The staff found the applicant's approach to monitoring activities to be acceptable because it is based on methods that are sufficient to predict the extent of degradation so that timely corrective or mitigative actions are possible.

Acceptance Criteria: Engineering evaluations of identified aging degradation, including loss of material, cracking, flow blockage, and loss of heat transfer aging effects, are used to confirm the ability of the component to perform its intended functions. Visual inspections of each of the subject heat exchangers are conducted by the applicant to detect fouling. If any type of degradation is found, the applicant takes further action via its corrective action program. The staff requested clarification regarding inspection procedures used to determine acceptability of the heat exchanger tubes. During a teleconference on August 6, 2002, the applicant indicated that the subject heat exchangers are very small heat exchangers and that all tubes are fully disassembled throughly cleaned and visually inspected. In addition, the applicant sited various inspection procedures that are used. **This is the other part of Confirmatory Item 3.0.3.17.2-1**.

The staff requested additional information from the applicant concerning the acceptance criteria for fouling management and whether the acceptance criteria include effective cleaning of fouling by organisms and maintenance of the coating or lining. The applicant responded, in a letter to the NRC dated May 14, 2002, that during maintenance, the tubes are cleaned and verification of effectiveness is accomplished by the turbine operability surveillance test. The applicant stated that these components do not have a coating or lining. The staff found the acceptance criteria specified by the applicant to ensure the intended functions of the SSCs which are inspected as a result of the heat exchanger inspection activities is adequate.

Operating Experience: The applicant stated that the heat exchanger inspection activities implement inspection and cleaning of heat exchangers. The applicant concluded that the PBAPS operating experience review identified no loss of pressure boundary integrity or heat transfer capability for these components as a result of aging degradation. The staff concludes that the aging management activities described above are based on plant experience. The staff agreed that these activities are effective at maintaining the intended function of the systems, structures, and components that may be served by the heat exchanger inspection activities, and can reasonably be expected to do so for the period of extended operation.

3.0.3.17.3 UFSAR Supplement

The staff reviewed Section A.2.10 of the UFSAR Supplement (Appendix A of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

3.0.3.17.4 Conclusions

The staff concludes that, with the exception of Confirmatory Item 3.0.3.17.2-1, the applicant has demonstrated that the aging effects associated with heat exchanger inspection activities will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement (Appendix of the LRA) contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.0.3.18 Lubricating and Fuel Oil Quality Testing Activities

The applicant described the lubricating and fuel oil quality testing activities AMP in Section B.2.1 of Appendix B of the LRA. The staff reviewed the applicant's description of the AMP in the LRA to determine whether the applicant has demonstrated that the lubricating and fuel oil quality testing activities AMP will adequately manage the effects of aging caused by components exposed to lubricating oil or fuel oil during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.0.3.18.1 Technical Information in the Application

The applicant stated that the lubricating and fuel oil quality testing activities AMP is used by PBAPS to manage loss of material, cracking, and heat transfer reduction in components that contain or are exposed to lubricating oil or fuel oil. Applicable systems include components in the engineered safety featured systems (high-pressure coolant injection (HPCI), core spray (CS), and reactor core isolation cooling (RCIC)), and the auxiliary systems (high-pressure service water (HPSW), fire protection (FP), and emergency diesel generator (EDG)). Lubricating and fuel oil quality testing activities are implemented through PBAPS procedures and include sampling and analysis of lubricating oil and fuel oil for detrimental contaminants, including water and particulates. The presence of water or particulates may also be indicative of in-leakage and corrosion product buildup. The applicant stated that the aging management review determined that diesel-driven fire pump fuel oil sampling methods would be enhanced to improve water detection capabilities. The applicant further stated that analyses of the diesel-driven fire pumps and EDG fuel oil samples will be enhanced to add testing for microbes detected in water.

The applicant indicated that the lubricating and fuel oil quality testing activities are preventive aging management activities that assure that potentially detrimental concentrations of water and particulates are not present in the oil. The applicant stated that these activities also provide for detection of loss of material and cracking in certain components containing lubricating or fuel oil. The applicant further stated that based on the use of industry standards and PBAPS operating experience, there is reasonable assurance that the lubricating and fuel oil quality testing activities will continue to adequately manage the effects of aging associated with components exposed to lubricating oil and fuel oil environments so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

3.0.3.18.2 Staff Evaluation

The staff's evaluation of the lubricating and fuel oil quality testing activities focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicates that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

Program Scope: The lubricating and fuel oil quality testing activities provide for sampling and testing of lubricating oil in components in the EDG, HPCI, HPSW, CS, and RCIC systems. This AMP also provides for sampling and testing of fuel oil in the EDG and diesel-driven fire pump fuel oil systems. The staff found the scope of the program to be acceptable because the applicant adequately addressed the components whose aging effects could be managed by the application of the lubricating and fuel oil quality testing activities.

Preventive or Mitigative Actions: The applicant stated that the lubricating and fuel oil quality testing activities are aging management activities that are preventive in that reasonable assurance is provided that potentially detrimental concentrations of contaminants such as water and particulate are not present in the oil. The staff believes that periodic cleaning of a tank removes sediments and that periodic draining of water collected at the bottom of a tank minimizes the amount of water and the length of the contact time. These measures are effective in mitigating corrosion inside fuel oil tanks. Therefore, the staff requested additional information from the applicant as to whether these measures are adopted in the AMP, and whether the EDG fuel oil tanks are considered to be the most bounding for the carbon steel diesel-driven fire pump fuel oil tanks. The staff also requested additional information on the specific actions that will be taken for the diesel-driven fire pump fuel oil tanks if EDG tank inspections and wall measurements indicate significant deterioration and/or significant wall thinning.

The applicant responded, in a letter to the NRC dated May 14, 2002, that Appendix B.2.1, "Lubricating and Fuel Oil Quality Testing Activities," of the LRA, includes oil sampling and testing activities to detect the presence of water and other detrimental contaminants in the oil. The sampling methods used will retrieve samples from the bottom of the emergency diesel generator and diesel-driven fire pump fuel storage tanks. Unacceptable water accumulation will be removed. In addition, this activity includes periodic draining of water from the bottom of the emergency diesel generator day tanks. However, the applicant indicated that this aging management activity does not include periodic cleaning of oil tanks.

Periodic cleaning of oil tanks is performed as part of the emergency diesel generator inspection activities (as discussed in Section B.2.4 of the LRA). The emergency diesel generator fuel oil storage tanks are drained and cleaned every 10 years. Residual fuel oil and sludge is removed, and the tank is washed with a cleaning solution and finally wiped until clean and dry. Tank wall thickness measurements are also taken, with no loss of wall thickness identified to date. The emergency diesel generator day tanks are periodically drained and the interiors of the tanks are visually inspected.

The HPCI lubricating oil storage tank is periodically drained, cleaned, and inspected as part of the HPCI turbine maintenance. This activity is performed as part of the HPCI and RCIC turbine inspection activities (as discussed in Section B.2.10 of the LRA). The bottom of the diesel-driven fire pump fuel oil storage tank is sampled for water every 92 days. This tank is located indoors in a sheltered environment, so there are no significant aging effects at the tank external surfaces. Frequent oil sampling precludes significant accumulation of water inside the tank. The oil sampling for the presence of water and contaminants is an adequate activity for managing loss of material of the carbon steel tank in a fuel oil environment.

The sampling activities of the diesel-driven fire pump fuel tanks are intended to detect accumulation of water and contaminants and thereby preclude corrosion within the tanks, similar to the emergency diesel generator fuel oil tanks sample activities. The four EDG fuel oil storage tanks, four EDG fuel oil day tanks, diesel fire pump fuel oil storage tank, and diesel fire pump fuel oil day tank are all constructed of carbon steel. The EDG fuel oil storage tanks are buried tanks, while the EDG fuel oil day tanks, diesel fire pump fuel oil storage tank, and diesel fire pump fuel oil day tank are located in a sheltered indoor environment. Since the buried environment is considered more aggressive than the sheltered environment, the EDG fuel oil storage tanks are considered to be the most bounding for these carbon steel fuel oil tanks. The applicant stated that if the EDG fuel oil storage tank inspections and wall measurements indicate significant deterioration and/or significant wall thinning, the condition will be documented in a condition report and the cause of the degradation will be determined. Generic implications for similar storage tanks would be considered and additional inspections performed as adequate.

On the basis of this review and the above additional information provided by the applicant, the staff found these activities adequate to mitigate aging degradation for components exposed to lubricating oil or fuel oil.

Parameters Monitored or Inspected: The applicant described lubricating oil sample analyses to be performed periodically in accordance with an approved PBAPS procedure. The applicant stated that samples are analyzed for attributes such as viscosity, moisture content, and pH. Samples of new fuel oil deliveries are analyzed for water and sediment. Emergency diesel generator and diesel-driven fire pump fuel oil storage tank samples are also periodically analyzed for the presence of water and the particulate content of the fuel. Enhancements to the diesel-driven fire pump fuel oil sampling techniques will be made to improve the methods for detection of water in the fuel. The applicant further stated that sampling activities for water that may be detected in the EDG and diesel-driven fire pump fuel oil systems would be enhanced to include an analysis for microbes. The staff found the description of the parameters monitored or inspected adequate to mitigate aging degradation for components exposed to lubricating oil or fuel oil because of the approved plant procedures and the additional enhancement activities.

Detection of Aging Effects: The applicant stated that testing of lubricating oil for water and contaminants provides a means for detecting loss of material and cracking in the HPCI, RCIC, and EDG systems, and monitors for water in-leakage in the HPCI and RCIC turbine lube oil coolers, HPSW and CS pump motor oil coolers, and the EDG lube oil cooler. The applicant further stated that testing of fuel oil for the presence of corrosion particles or water provides a means for detecting loss of material for fuel oil storage tanks and underground fuel oil piping.

The staff indicated that corrosion may occur at locations in which contaminants may accumulate, such as tank bottoms. Accordingly, the staff believes that the subject AMP needs to effectively ensure that significant degradation is not occurring and the component intended function would be maintained during the period of extended operation; thickness measurements of tank bottom would be an acceptable verification technique. Therefore, the staff requested additional information from the applicant to address the issue of verification and the applicability of one of the applicant’s other AMPs (the emergency diesel generator inspection activities AMP as discussed in Section B.2.4 of the LRA) as the corresponding verification program.

The applicant responded, in a letter to the NRC dated May 14, 2002, with the following information. The emergency diesel generator fuel oil storage and day tanks and the diesel-driven fire pump fuel oil storage and day tanks are periodically sampled to confirm that water and contaminants are not accumulating. This frequent sampling precludes long-term accumulation of contaminants at the bottom of these tanks. In addition to sampling, the emergency diesel generator fuel oil storage and day tanks are periodically inspected as part of the emergency diesel generator inspection activities AMP as discussed in Section B.2.4 of the LRA. This aging management activity is cross-referenced with the lubricating and fuel oil quality testing activities in Table 3.3-16 of the LRA. The EDG inspection activity includes wall thickness measurements for the emergency diesel generator fuel oil storage tanks. The applicant stated that this inspection activity confirms the effectiveness of periodic sampling to prevent significant corrosion of the tank bottom.

The staff also requested further information on whether the UT and visual inspection activities described in B2.4 of the LRA are applied to components in systems other than the EDG. The applicant responded, in the same letter to the NRC dated May 14, 2002, stating that experience to date with the visual inspections of the emergency diesel generator fuel oil day tanks and storage tanks has not revealed significant deterioration. In addition, experience with wall thickness measurements of the emergency diesel generator fuel oil storage tanks has not revealed any significant wall thinning. The applicant further stated that since the EDG tank inspections have validated the effectiveness of the fuel oil sampling activities, it is not considered necessary to perform internal visual inspections of the diesel-driven fire pump fuel oil tanks.

The staff found this program attribute acceptable because the applicant has provided comprehensive information both in the LRA and in the response to the staff's RAIs on the applicant's approach to detecting applicable aging effects and the program activities may be relied upon to provide reasonable assurance that aging effects will be detected before there is loss of intended function.

Monitoring and Trending: The applicant stated that the lubricating oil and fuel oil analyses are regularly scheduled and the results are evaluated to aid in the identification of potential adverse conditions. Section A.1.2.3.5 of NUREG-1800 states that it is necessary to confirm that the next scheduled inspection will occur before a loss of SC intended function. Therefore, the staff requested additional information from the applicant to provide the schedule for the lubricating oil and fuel oil analyses. The applicant responded, in a letter to the NRC dated May 14, 2002, with the following schedule information:

The emergency diesel generator lubricating oil is sampled quarterly (every 92 days).

The emergency diesel generator fuel oil is sampled and analyzed upon delivery to the station, prior to being delivered to onsite storage tanks.

The emergency diesel generator main fuel oil storage tanks are sampled for water accumulation, with any accumulated water analyzed for microbes, every 31 days.

The emergency diesel generator main fuel oil storage tanks are sampled for particulate contamination every 31 days.

The emergency diesel generator fuel oil day tanks are sampled for water accumulation, with any accumulated water analyzed for microbes, every 31 days.

The diesel-driven fire pump fuel oil is sampled and analyzed upon delivery to the station, prior to being delivered to onsite storage tanks.

The diesel-driven fire pump fuel oil storage tank will be sampled for viscosity, sediment, and water accumulation, with any accumulated water analyzed for microbes, every 92 days (quarterly).

HPCI lubricating oil is sampled during the quarterly HPCI pump test.

RCIC lubricating oil is sampled during the quarterly RCIC pump test.

The staff found the applicant's approach to monitoring activities to be acceptable because it is based on methods that are sufficient to predict the extent of degradation so that timely corrective or mitigative actions are possible.

Acceptance Criteria: The applicant stated that the lubricating and fuel oil quality testing activities are performed in accordance with approved PBAPS procedures which contain quantitative and qualitative acceptance criteria. Lubricating oil analysis acceptance criteria are based on deviations from the physical requirements identified in the oil type listing. The acceptability of lubricating oil test results is based upon comparison with new oil values, published data, or previous oil analysis results. Oil is acceptable if viscosity changes by no more than +15% to -10%, percent water is less than or equal to 0.10, and pH is within the required values for the type of oil being analyzed. EDG fuel oil analysis acceptance criteria are contained in the PBAPS Technical Specifications and are based on the requirements of ASTM D2276-78 and ASTM D975-81. A fuel oil testing procedure based on ASTM D975-81 requires that new fuel oil contain no visible water or sediment.

PBAPS Technical Specifications require periodic sampling of the EDG fuel oil for particulates and the presence of water. Tests for particulates use the methods specified in ASTM D2276-78 to provide assurance that the particulate limit of 10 mg/L is not exceeded. Plant procedures limit EDG fuel oil storage tank water accumulation to 100 ml/L for samples taken from the bottom of the tank and EDG fuel oil day tank water accumulation to none present at the conclusion of the surveillance test. Diesel-driven fire pump fuel oil analysis acceptance criteria are based on ASTM D975-74, which requires that the fuel contain a maximum of 0.05% by volume of water and sediment. Fuel oil analysis for both the EDG and diesel-driven fire pump fuel samples will be enhanced to analyze any water discovered in the storage or day tanks for the presence of microbes. Based on the information provided above, the staff found the acceptance criteria to be adequate to ensure the intended functions of the systems, structures, and components that may be served by the lubricating and fuel oil quality testing activities because they are based on approved PBAPS procedures and ASTM standards.

Operating Experience: The applicant found that the overall effectiveness of the lubricating and fuel oil quality testing activities is supported by the operating experience that PBAPS had with lubricating oil and fuel oil systems. The applicant stated that minor contamination events such as sediment in the diesel-driven fire pump fuel oil day tank (one event), water in the diesel-driven fire pump fuel oil storage tank (two events), and water in the EDG fuel oil storage tanks (two events in 1988) have been detected and corrected in a timely manner. Since moving the diesel-driven fire pump fuel oil storage tank indoors, there have been no incidents of water detected in the tank. The applicant further stated that there have been no age-related component failures resulting in a loss of function of systems in lubricating oil or fuel oil environments. Based on the information above, the staff requested additional information from the applicant concerning whether any of these events were related to contamination of the tank bottoms. The staff indicated in its RAI that it was not certain whether there is a verification program in place to assure the effectiveness of this AMP.

The applicant responded, in a letter to the NRC dated May 14, 2002, with the following additional information. The applicant stated that the described events involved the discovery of contaminants (sediment and water) in the bottom of the identified fuel oil storage tanks. As stated in the LRA, water was found in the diesel-driven fire pump fuel oil storage tank before the tank was relocated indoors. The existing underground diesel-driven fire pump fuel oil storage tank was abandoned in place and a new fuel oil storage tank was installed indoors. The applicant indicated that these events are not related to contaminations of the tank bottoms and that these events were not caused by degradation of the tank bottoms, nor did these events result in degradation of the tank bottoms. The diesel-driven fire pump fuel oil storage tank was replaced and relocated indoors to comply with Environmental Protection Agency regulations. The diesel-driven fire pump fuel oil day tank is also located indoors.

The applicant also stated that the EDG fuel oil storage tanks are buried tanks and are periodically drained, cleaned, and inspected. The most recent inspections, performed in 1995 and 1996, indicated no significant loss of tank wall thickness. In all of these events, sediment or water was discovered in a timely manner and removed. Timely detection and removal of these contaminants provides reasonable assurance that detrimental concentrations of contaminants are not present.

The EDG fuel oil storage and day tanks are periodically inspected as part of the emergency diesel generator inspection activities AMP, as discussed in Section B.2.4 of the LRA. The inspection activity includes wall thickness measurements for the emergency diesel generator fuel oil storage tanks. The EDG fuel oil tanks are considered bounding for the carbon steel diesel-driven fire pump fuel oil tanks. These EDG tank inspection activities confirm the effectiveness of the lubricating and fuel oil quality testing activities AMP.

The staff found that the aging management activities described above are based on plant experience. Because of the review of the information provided in the LRA and the evaluation of the additional information provided by the applicant above the staff agreed that these activities are effective in maintaining the intended function of the systems, structures, and components that may be served by the lubricating and fuel oil quality testing activities, and can reasonably be expected to do so for the period of extended operation.

3.0.3.18.3 UFSAR Supplement

The staff reviewed Section A.2.1 of the UFSAR Supplement (Appendix A of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

3.0.3.18.4 Conclusions

The staff concludes that the applicant has demonstrated that the aging effects associated with lubricating and fuel oil quality testing activities will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement (Appendix A of the LRA) contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.0.3.19 One-Time Piping Inspection Activities

In the evaluation of the aging management of the components in the standby liquid control system (SBLC), the staff had concerns about the adequacy of the SBLC system surveillance activities in Section B1.13 of Appendix B of the LRA used by the applicant to manage applicable aging effects of the solution tank. The applicant stated that the surveillance activities monitor the SBLC solution tank liquid level on a daily basis in accordance with a PBAPS procedure. The basis of the staff's concern was that aging management programs are generally of four types: prevention, mitigation, condition monitoring, or performance monitoring, as described in Section A.1.1, "Branch Technical Position of Aging Management Review," of NUREG-1800. An AMP that relies only on liquid-level monitoring (as do the SBLC system surveillance activities) may act as an indicator of throughwall cracks and/or openings that have already developed. It is not an effective indicator of aging degradation already in progress (no matter how extensive) but not actually throughwall. Borated water can induce corrosion and cracking at the tank bottom due to the presence of chlorides, sulfates, and contaminants. Control and monitoring of water chemistry provides an indicator of aging degradation prior to loss of component intended function. A one-time inspection provides a verification of the effectiveness of managing the aging degradation. Therefore, the staff requested additional information from the applicant on (1) why the SBLC system surveillance activities do not include preventive or mitigative actions such as controlling and monitoring the borated water chemistry; and (2) why there is not a verification program such as on-time inspection to ensure that aging degradation is mitigated.

The applicant responded, in a letter to the NRC dated May 14, 2002, that the borated water stored in the standby liquid control solution tank is prepared by mixing an enriched chemical material with demineralized water to form a sodium pentaborate solution. The sodium pentaborate solution provides a relatively mild environment whose pH is slightly basic. The enriched chemical material is purchased as safety-related material under an approved purchase specification. The purchase specification requirements include impurity limits for chlorides, sulfates, and other contaminants that are based on industry standards. Each batch of material is supplied with a certified chemical analysis that typically indicates impurity levels well below the established limits. The water source is demineralized water from the water treatment system, and is subject to water chemistry controls. Since impurities are controlled when preparing the tank solution, and there is no source for contaminants to subsequently enter the closed tank, the level of detrimental contaminants is adequately controlled and aging degradation is mitigated.

In addition, based on discussions with the NRC staff and representatives from Argonne National Laboratory during the RAI reviews and two teleconference calls, the applicant has decided to modify the aging management activities associated with the standby liquid control system. In the same letter to the NRC dated May 14, 2002, the applicant stated that the modified aging management approach for the standby liquid control system includes water chemistry controls applied to the demineralized water system and a one-time inspection of a representative section of standby liquid control system piping. The one-time inspection piping is a new activity. LRA Appendix B.1.13, “Standby Liquid Control System Surveillance Activities,” will be deleted. The applicant further stated that this modified approach for aging management of the standby liquid control system is the same approach that is described in NUREG-1803, “Safety Evaluation Report Related to the License Renewal of Edwin I. Hatch Nuclear Plant, Units 1 and 2.” The staff’s evaluation of the water chemistry controls activities applied to the demineralized water system is discussed in Section 3.0.3.4 of this SER. The evaluation of the one-time piping inspection activities is provided below.

The applicant described the one-time piping inspection activities aging management program in Section B.3.3 of Appendix B of the LRA. The one-time piping inspection activities AMP (in conjunction with the demineralized water and condensate storage tank chemistry AMP (Section B1.4)) is used by PBAPS to manage loss of material and cracking in components that contain or are exposed to demineralized water (including borated) or condensate storage water. The staff reviewed the applicant’s description of the AMP in the LRA to determine whether the applicant has demonstrated that the one-time piping inspection activities AMP will adequately manage the effects of aging caused by components exposed to demineralized water (including borated water) or condensate storage water during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.0.3.19.1 Technical Information in the Application

The applicant described the one-time piping inspection activities aging management program in Section B3.3 of the LRA. The one-time piping inspection activities is a new activity that will be added to confirm the effectiveness of the water chemistry programs in managing the effects of aging in the standby liquid control system. This activity will consist of a one-time inspection of selected system piping to verify the integrity of the piping and confirm the absence of identified aging effects. The inspections will be condition monitoring examinations intended to verify that existing environmental conditions are not causing material degradation that could result in a loss of intended functions.

3.0.3.19.2 Staff Evaluation

The staff's evaluation of the one-time piping inspection activities focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicates that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

Program Scope: The applicant described the scope of this activity as including piping inspections at a susceptible location in the following systems:

- standby liquid control system
- auxiliary steam system
- plant equipment and floor drain system
- service water system
- radiation monitoring

The staff found the scope of the program to be acceptable because the applicant adequately addressed the components whose aging effects could be managed by the application of this activity.

Preventive or Mitigative Actions: The applicant stated that the piping inspection activities will be condition monitoring activities that identify loss of material or cracking aging effects as applicable for the material and environment. No preventive or mitigating attributes will be associated with the one-time piping inspection activities. The staff considers inspection activities a means of detecting, not preventing, aging and, therefore, agrees that there are no preventive actions associated with the one-time system piping inspection activities.

Parameters Monitored or Inspected: The applicant stated that the one-time piping inspection activities will provide for a one-time inspection to determine whether there has been loss of material or cracking in the subject piping, as applicable for the system material and environment. The inspection activities will confirm the pressure boundary integrity of the piping system. Inspections are performed in accordance with the requirements of the American Society of Mechanical Engineers (ASME) Code, by using volumetric nondestructive examination (NDE) methods. The staff found the applicant's approach following the ASME Code to be capable of adequately detecting the applicable aging effects using the one-time system piping inspection activities.

Detection of Aging Effects: The applicant stated that the one-time piping inspection activities will be undertaken to provide reasonable assurance that there is no loss of material or cracking, as adequate for the system material and environment, that would result in loss of pressure boundary intended function of the piping. Qualified personnel following procedures consistent with the ASME Code will perform the nondestructive examinations. The staff requested the applicant to provide information regarding when this one-time inspection would occur. By teleconference call, on August 8, 2002, the applicant indicated that this one-time inspection will occur before the end of plant life, between the years 30 to 40. **This is a Confirmatory Item 3.0.3.19.2-1**. The staff found the description of the detection of aging effects adequate. The staff found this program attribute acceptable because the applicants approach in detecting applicable aging effects is consistent with ASME Code and the program activities may be relied upon to provide reasonable assurance that aging effects will be detected before there is loss of intended function.

Monitoring and Trending: The applicant stated that the results of the one-time piping inspection activities will be evaluated. The scope and frequency of subsequent examinations will be based on the results of the initial inspections. The staff found the applicant's approach to monitoring activities to be acceptable because it is a new activity and because the results of the initial inspections will be used to determine the scope and frequency of subsequent examinations. Therefore this approach is based on methods that are sufficient to predict the extent of degradation so that timely corrective or mitigative actions are possible.

Acceptance Criteria: The applicant stated that the one-time piping inspection activities acceptance criteria will be used to ensure that there is no unacceptable loss of material or cracking, as applicable for the material and environment of the piping system. Indications of corrosion or cracking will be evaluated by further engineering analysis and, if warranted, additional inspections performed. The applicant further stated that the inspection acceptance criteria will provide assurance that the minimum wall thickness requirements for the piping continue to be met during the period of extended operation. The staff found the acceptance criteria specified by the applicant to be adequate to ensure the intended functions of the systems, structures, and components that may be served by the one-time piping inspection activities.

Operating Experience: The one-time piping inspection activities are new, and therefore there is no operating history associated with these activities. However, these inspection activities will use techniques with demonstrated capability to detect loss of material or cracking. This inspection will be performed utilizing approved procedures and qualified personnel. The staff finds the one-time inspection program acceptable because the results of the initial inspection will be used to determine the scope and frequency of subsequent examinations which are sufficient to predict degradation so that timely corrections actions are possible.

3.0.3.19.3 UFSAR Supplement

The staff reviewed Section A.3.3 of the UFSAR Supplement (Appendix A of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

3.0.3.19.4 Conclusions

The staff concludes that the applicant has demonstrated that the aging effects associated with one-time piping inspection activities will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement (Appendix A of the LRA) contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.0.3.20 Reactor Materials Surveillance Program

3.0.3.20.1 Technical Information in the Application

The applicant described its reactor materials surveillance (RMS) program in Sections A.1.12 and B.1.12 of the LRA. The reactor materials surveillance program is an existing program at Peach Bottom. It is based on a detailed evaluation of the Plant Peach Bottom Unit 1 and Unit 2 RPV beltline materials. The LRA indicates that the BWRVIP is developing an Integrated Surveillance Program (ISP) for all domestic operating BWRs as allowed by 10 CFR Part 50 Appendix H. The ISP was submitted to the NRC by BWRVIP for review and approval. The NRC approved a 40 year program. Both of the Plant Peach Bottom RPVs are included in the program. The subject program will be incorporated into the ISP, as described in BWRVIP-78.

3.0.3.20.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the LRA regarding the applicant's demonstration of the reactor materials surveillance program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

The staff evaluation of Reactor Materials Surveillance Program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmative process, administrative controls, and operating experience. The applicant indicates that the corrective actions, confirmation process, and administrative controls are part of the site controlled quality assurance program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

Section B.1.12 of the LRA describes the reactor materials surveillance program for Plant Peach Bottom. The reactor materials surveillance program employs the program documented in BWRVIP-78, "BWR Vessel and Internals Project, BWR Integrated Surveillance Program Plan." The staff has approved a BWR intergrated surveillance program for 40 years; but, has not approved a program for 60 years, the extended license renewal period. For open issues between the BWRVIP and NRC, Exelon will work as part of the BWRVIP to resolve these issues generically. When the issues are 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). Since the applicant and the BWRVIP have procedures for resolving open items, the response by the applicant is acceptable to the staff. Because the report is not currently approved for the license renewal term the staff will condition the license and this is discussed in Section 3.0.3.9 of this SER.

Program Scope: The objective of the subject program is to monitor the effects of neutron embrittlement on the reactor vessel beltline materials (plates and welds). The staff finds that the scope of the subject AMP is adequate because it applies to vessel shell courses exposed to fluence greater than 10^{17} n/cm^{2} (E>1Mev).

Preventive or Mitigative Actions: The subject program is a condition monitoring program. There are no preventive or mitigative attributes associated with the subject program.

Parameters Monitored or Inspected: The subject program monitors Charpy V-Notch 42-Joule (30 ft-lb) transition temperature, upper shelf energy, and neutron fluence consistent with the requirements of ASTM E 185 and 10 CFR Part 50, Appendix H. Since the program monitors the parameters required by the regulations, the parameters monitored by the program are acceptable.

Detection of Aging Effects: The subject program monitors the effects of neutron irradiation embrittlement by evaluating the loss of fracture toughness. This is acceptable to the staff because it allows for detection of the effects of neutron irradiation embrittlement before there is a loss of the component intended function.

Monitoring and Trending: To evaluate whether the reactor materials surveillance program provides sufficient data for monitoring the extent of neutron irradiation embrittlement during the license renewal period, the staff issued RAI 3.1-15 requesting the applicant to provide information about whether the existing Plant Peach Bottom reactor surveillance program will be revised to satisfy the following attributes:

- Capsules must be removed periodically to determine the rate of embrittlement and at least one capsule with 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 must 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 Plant Peach Bottom during the license renewal period, the applicant must 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.

In addition the applicant has indicated in the subject program that the provisions of the Integrated Surveillance Program (ISP) as described in BWRVIP-78 will be implemented. As part of RAI 3.1-15, the staff requested information about the schedule for implementing the ISP at Plant Peach Bottom and about how the proposed ISP would satisfy the ISP criteria in 10 CFR Part 50, Appendix H, and the attributes discussed above. In response to RAI 3.1-15, the applicant submitted the following information.

The BWRVIP has developed an ISP for 40 years 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 its 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 10 CFR Part 50, 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 for 60 years, 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 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.

The staff finds that applicant's response to RAI 3.1-15 acceptable.

Acceptance Criteria: Regulatory Guide 1.99, Revision 2, and ASTM E185 supply the basis for Plant Peach Bottom reactor materials surveillance acceptance criteria. The applicant has incorporated these documents into the LRA by specific reference. Appendix H to 10 CFR Part 50 requires the reactor vessel materials surveillance program to comply with ASTM E185. The staff finds that the acceptance criteria based on Regulatory Guide 1.99, Revision 2, and ASTM E185 are acceptable because they are based on regulatory guidance and regulatory requirements.

Operating Experience: PBAPS Units 2 and 3 have tested surveillance capsules containing plate and weld material, and the results are consistent with Regulatory Guide 1.99, Revision 2, predictions. The staff concludes that the operating experience supports the licensee's program.

3.0.3.20.3 UFSAR Supplement

The applicant describes the reactor materials surveillance program as an existing program in Section A1.12 of the LRA. The program uses periodic testing of metallurgical surveillance samples to monitor the loss of fracture toughness of the reactor pressure vessel beltline region materials consistent with the requirements of 10 CFR Part 50, Appendix H, and ASTM E185. The applicant does not include a summary of the BWR Integrated Surveillance Program, which it intends to use at Peach Bottom. In RAI 3.1-17, the staff requested the applicant to include information about the BWR Integrated Surveillance Program, which should include reference to BWRVIP reports. In response to this RAI, the applicant stated that 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 10 CFR Part 50, Appendix H. **This is Confirmatory Item 3.0.3.20.3-1**.

The staff reviewed Section A.1.12 of the UFSAR Supplement (Appendix A of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

3.0.3.20.4 Conclusions

The staff concludes that the applicant has demonstrated that the aging effects associated with reactor materials surveillance program will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement, with the exception of Confirmatory Item 3.0.3.20.3-1, (Appendix A of the LRA) contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.0.3.21 Torus Piping Inspection Activities

The applicant described the Torus Piping Inspection Activities program in Section B.3.1 of Appendix B of the LRA. The applicant credits this program with managing the aging effects of the carbon steel piping located at the water-air interface in the torus of the primary containment. The staff reviewed the applicant's description of the program to determine whether the applicant has demonstrated that the program will adequately manage the applicable effects of aging caused by the torus piping exposed to the torus water-air interface or wetted air environment during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.0.3.21.1 Technical Information in the Application

In Section B.3.1 of the LRA, the applicant identified the torus piping inspection activities as a new aging management program that will be used in conjunction with the Torus Water

Chemistry Activities (Section B.1.5 of the LRA) to manage loss of material of torus piping in the high-pressure cooling injection (HPCI), core spray, reactor core isolation cooling (RCIC), residual heat removal (RHR), and main steam systems exposed to the torus water-air interface environment. The AMP consists of a one-time inspection of the wall thickness of selected torus piping by ultrasonic test to confirm that there is no unacceptable loss of material of the torus piping near the waterline. The scope and interval of the subsequent examinations will be based on the results of the one-time inspection. The AMP, by itself, also manages loss of material of the piping, valves, and steam traps of the HPCI, RCIC, and main steam systems exposed to the wetted air environment above the water line. The torus piping components that are located above the waterline are subjected to a humid wetted air environment that is less corrosive than the torus water-air interface environment. The applicant stated that the results of the one-time inspection will bound the torus piping components exposed to the wetted air environment.

3.0.3.21.2 Staff Evaluation

The staff's evaluation of the torus piping inspection activities program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of these three elements is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

Program Scope: The applicant stated that the AMP will examine a susceptible location on a representative sample of carbon steel piping exposed to the torus water-air interface environment to assure there is no unacceptable loss of material. The AMP will provide confirmation that the main steam, HPCI, and RCIC piping discharging to the torus is in acceptable condition. The results of this inspection will bound the torus-connected piping and components exposed to the wetted air environment. The staff found that Tables 3.2-2 and 3.2-5 of the LRA are inconsistent with the description of the program scope in the Torus Piping Inspection Activities AMP. Tables 3.2-2 and 3.2-5 of the LRA show that the AMP is credited to manage the loss of material for the components in the core spray and residual heat removal systems. The program scope, however, does not include these two systems. In the RAI B3.1-1, the staff requested a clarification of why the torus piping of the core spray and residual heat removal systems is not included in the program scope. By letter dated June 10, 2002, the applicant stated that the torus piping of the core spray (CS) and residual heat removal (RHR) systems is bounded by the scope of the Torus Piping Inspection Activities but is not in the one-time inspection scope. This is because the internal environment of the piping of the CS and RHR systems above the water line is torus-grade water. The internal environment of the main steam SRV, HPCI turbine, and RCIC turbine above the water line is wetted gas. It was determined that the piping with wetted gas both internally and externally would be more susceptible to loss of material at the water-gas interface and would therefore bound the other piping in the torus. The potential loss of material at the water-gas interface is due to normal, small torus water level changes that alternately wet and dry the piping. For the CS and RHR piping, this effect only occurs on the outside of the pipe, and for main steam SRV, HPCI turbine, and RCIC turbine piping, the effect occurs on both the inside and the outside of the piping. The torus piping inspection activities AMP is credited in the system tables because the results of the one-time inspection will be evaluated for applicability to the CS and RHR piping in the torus as well as the other piping described in the AMP. Apparent unacceptable indications of corrosion will be evaluated by further engineering analysis for their applicability to CS, RHR, main steam SRV, HPCI turbine, and RCIC turbine piping and, if warranted, additional inspections will be performed. Based on the applicant's response, the staff finds the scope of the program to be acceptable because the applicant adequately addressed the systems and components whose aging effects could be managed by the application of this activity.

Preventive Actions: The applicant described this AMP as a condition monitoring AMP. The applicant did not provide any preventive or mitigation actions for this activity, nor did the staff identify a need for such.

Parameters Monitored or Inspected: The applicant stated that the AMP will provide a one-time inspection of wall thickness to assure there is no unacceptable loss of material. The staff finds inspection of wall thickness acceptable because loss of material will cause reduction of wall thickness. Thus, the parameter inspected is directly linked to degradation of the component.

Detection of Aging Effects: The applicant stated that an ultrasonic test (UT) will be performed to measure the wall thickness. The inspection will be based on the guidance provided in ASME Code, Section V, 1989 edition. The scope and frequency of the subsequent examinations will be based on the results of the inspection. The results of the inspection will bound the torus-connected piping and components exposed to the wetted air environment. The staff finds that the Torus Piping Inspection Activities program has an adequate inspection scope and schedule and uses an adequate inspection technique, and thus may be relied upon to provide reasonable assurance that aging effects will be detected before there is a loss of intended function.

Monitoring and Trending: The applicant stated that results of the torus piping inspection activities will be evaluated. The scope and frequency of the subsequent examinations will be based on the results of the initial inspection. The staff finds this AMP sufficient to predict the extent of degradation so that timely corrective actions are possible. This AMP is therefore acceptable.

Acceptance Criteria: The applicant stated that unacceptable indications of corrosion will be evaluated further by engineering analysis and, if warranted, additional inspection will be performed. The inspection acceptance criteria will assure that the minimum wall thickness requirements for the torus piping continue to be met during the period of the extended operation. The staff finds the acceptance criteria acceptable because the intended function of the component will be maintained by maintaining the minimum wall thickness.

Operating Experience: The Torus Piping Inspection Activities program is a new program; thus, the applicant did not submit Peach Bottom-specific operating experience. However, industry experience shows no failures of torus piping at the torus water-air interface. Thus, the staff finds that the operating experience is satisfactorily incorporated into the development of this new program and supports the attributes of this program.

3.0.3.21.3 UFSAR Supplement

The staff reviewed Section A.3.1 of the UFSAR Supplement (Appendix A of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

3.0.3.21.4 Conclusions

The staff concludes that the applicant has demonstrated that the aging effects associated with torus piping inspection activities will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement (Appendix A of the LRA) contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.0.4 Quality Assurance Program

In accordance with 10 CFR 54.21(a)(3), an applicant is required to demonstrate that the effects of aging on SCs that are subject to an AMR will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation. Consistent with this approach, Section A.2, "Quality Assurance for Aging Management Programs (Branch Technical Position IQMB-1)", of the NRC's "Standard Review Plan for the License Renewal Applications for Nuclear Power Plants" (SRP-LR) states that an applicant's aging management programs should contain the elements of corrective actions, confirmation process, and administrative controls in order to ensure proper aging management. The SRP-LR also states that license renewal applicants can rely on the existing requirements in 10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," to satisfy these program elements or attributes.

3.0.4.1 Summary of Technical Information in the Application

Quality Assurance Review of Appendix A, "UFSAR Supplement"

Appendix A, Section A.1, "Existing Aging Management Activities" of the PBAPS LRA did not provide a description of how the applicant's 10 CFR Part 50, Appendix B, quality assurance program addressed the elements of corrective actions, confirmation process, and administrative controls in order to ensure proper aging management.

Quality Assurance Review of Appendix B, "Aging Management Activities"

Appendix B, Section B.1, "Existing Aging Management Activities," of the LRA provides an aging management activity summary for each unique structure, component, or commodity group determined to require aging management during the period of extended operation and includes a description of each attribute associated with the described aging management activities. However, Appendix B to the LRA does not provide a description of how the applicant's quality assurance program (QAP)specifically addresses corrective action, confirmation process, and administrative controls for which credit is being sought.

3.0.4.2 Staff Evaluation

The staff reviewed the aging management program activities defined in the Applicant's Appendix A, Section A.1, "Existing Aging Management Activities," and to the aging management program activities defined in Appendix B, "Aging Management Activities," of the applicant's LRA.

The staff, in order to address the lack of information regarding the applicant's QAP as it relates to the LRA Appendix A activities, requested additional information. In RAI A.2-1, dated January 23, 2002, the staff asked Exelon to provide a description of how the QAP specifically addresses the attributes of corrective actions, confirmative process, and administrative controls for the aging management programs during the period of extended operation. Exelon's response to the RAI, dated February 28, 2002, stated that the Corrective Action Program (CAP) provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences. Administrative controls are in place for existing aging management programs and activities and for the currently required portions of enhanced programs and activities and will also be applied to new and enhanced programs and activities as they are implemented. To address the confirmation process attribute, the RAI stated that PBAPS performs an effectiveness review for all root cause analysis corrective actions to prevent recurrence and other items as assigned by the PBAPS Management Review Committee. If corrective actions to prevent recurrence are determined to be ineffective, this deficiency is addressed by the existing condition report or a new condition report is generated to address the deficiency and initiate resolution. In addition the response stated that these programs and activities will be performed in accordance with written procedures which will be reviewed and approved in accordance with the applicant's 10 CFR Part 50, Appendix B, quality assurance program. The applicant also added a new section, Section A.1.17, "Corrective Action Program," which describes the three attributes of interest and addresses the staff's concern. The staff finds that the applicant's response to the RAI adequately addressed the staff guidance provided in the SRP-LR. With the applicant's commitment to include in the UFSAR Supplement a new section, Section A.1.17, that describes how the CAP would provide a description of how the attributes of corrective action, confirmation process, and administrative controls are met for the aging management programs the staff will be able to conclude that an adequate program summary has been provided in accordince with the requirements of 10 CFR 54.21(d). **This is Confirmatory Item 3.0.4-1**.

The staff reviewed the aging management program activities defined in Appendix B, "Aging Management Activities," of the applicant's LRA. Section B.1, "Existing Aging Management Activities," of Appendix B to the LRA provides an aging management activity summary for each unique structure, component, or commodity group determined to require aging management during the period of extended operation and includes a description of each attribute associated with the described aging management activities. However, Appendix B to the LRA does not provide a description of how the QAP specifically addresses corrective action, confirmation process, and administrative controls for which credit is being sought. In RAI B.1-1, dated January 23, 2002, the staff asked Exelon to provide a description of how the applicant's 10 CFR Part 50, Appendix B, QAP specifically addresses corrective action, confirmation process, and administrative controls for the aging management programs, during the period of extended operation, for both safety-related and non-safety-related SSCs that are within the scope of license renewal.

Exelon's response to the RAI, dated February 28, 2002, further clarified that the QAP , which determines the causes of, and corrective actions for, conditions adverse to quality, was credited for license renewal and also determines corrective action taken to preclude repetition of significant conditions adverse to quality. Exelon procedure AD-AA-101, "Processing of Procedures and T&RMs" (administrative controls), governs creation and revision of standard or site-specific procedures and was the basis for this attribute in all PBAPS LRA Appendix B programs. Exelon stated that the CAP and procedure AD-AA-101, which apply to all of the programs credited for license renewal at PBAPS, are in accordance with the QAP, which complies with 10 CFR 50, Appendix B. To address the confirmation process attribute, the RAI stated that PBAPS performs an effectiveness review for all root cause analysis corrective actions to prevent recurrence and other items as assigned by the PBAPS Management Review Committee. If corrective actions to prevent recurrence are determined to be ineffective, this deficiency is addressed by the existing condition report or a new condition report is generated to address the deficiency and initiate resolution. The response also stated that the applicant has established and implemented a QAP that conforms to the criteria set forth in 10 CFR Part 50, Appendix B, which addresses all aspects of quality assurance. The elements of the program that are most pertinent to the aging management programs credited for license renewal are corrective action and document control, which apply to all SSCs within the scope of license renewal. Exelon's response to the RAI also stated that a new section, Section B.1.17, "Corrective Action Program," would be added to Appendix B of the LRA and would provide a description of how corrective actions, confirmation process, and administrative controls are met for all programs. The applicant also stated that the PBAPS CAP will also be applied to future implementation requirements during the term of the renewed license in accordance with the requirements of 10 CFR 54.4, "Scope," and 10 CFR 54.21, "Contents of Application — Technical Information." The staff finds that the applicant's response to the RAI adequately addressed the staff guidance provided in the SRP-LR.

The staff finds that the applicant's response to the staff's request for additional information, dated February 28, 2002, provides a sufficient description of the quality assurance programs, attributes, and activities for managing the effects of aging. Based on the review described above, the NRC staff finds that the applicant's aging management programs and activities contain the necessary aspects of quality assurance, including the elements of corrective actions, confirmation process, and administrative controls, to ensure proper management of applicable aging effects.

3.0.4.3 Conclusions

The staff finds that the quality assurance attributes are consistent with 10 CFR 54.21(a)(3) and the staff's Branch Technical Position IQMB-1. Therefore, the applicant's quality assurance description for its aging management programs is acceptable. The staff finds, with the exception of Confirmatory Item 3.0.4.-1, that the applicant's UFSAR Supplement (Appendix A of the LRA) and the February 28, 2002, response to the staff's RAI provides a sufficient description of the quality assurance programs, attributes, and activities for managing the effects of aging as required by 10 CFR 54.21(d).

3.0.5 NRC Staff Reliance Upon Common Aging Management Programs

In Sections 3.0.3.1 through 3.0.3.21 and 3.0.4 of this SER the staff reviews common AMPs. In its review of the AMPs as they apply to specific components, systems, and structures in the following sections (Section 3.1 through 3.6), the NRC staff has relied on the adequacy of the common AMPs in Sections 3.0.3.1 through 3.0.3.21 and 3.0.4 of the SER. In several cases, open or confirmatory items were identified in the review of these common AMPs. The staff's conclusions regarding the adequacy of AMPs for specific components, systems, and structures is conditioned upon satisfactory resolution of open and confirmatory items identified in the review of the common AMPs.

3.1 Aging Management of Reactor Coolant System

The applicant described its AMR of the reactor pressure vessel and internals, fuel assemblies, reactor vessel instrumentation system, and reactor recirculation system for license renewal in LRA Section 3.0, "Aging Management Review Results," and Section 3.1, "Aging Management of Reactor Coolant System." The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging on the reactor coolant system (RCS) are adequately managed so that the intended functions will be maintained in a manner that is consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3). The intended functions, environments, materials, aging effects, and aging management activities for each component group in the reactor coolant system are listed in Tables 3.1-1, 3.1-2, 3.1-3 and 3.1-4 of the LRA. A component group is a group of components that have the same intended functions, were constructed using similar materials, and operate in similar environments.

Environments are defined in Section 3.0 of the LRA and include steam, reactor coolant, and sheltered. The sheltered environment is an indoor environment where components are protected from outdoor moisture. The sheltered environment atmosphere for RCS is a nitrogen environment with humidity.

3.1.1 Reactor Pressure Vessel and Internals

3.1.1.1 Technical Information in the Application

The RPV is a vertical, cylindrical pressure vessel with hemispheric heads of welded construction. The cylindrical shell and bottom head are fabricated of low-alloy steel plates and clad on the interior with a stainless steel and an Inconel overlay, respectively. The top head is a low-alloy steel forging. No stainless steel clad is supplied on the interior of the top head because it is exposed to a saturated steam environment throughout its operating lifetime. The reactor pressure vessel components that are within the scope of license renewal are shell courses, top and bottom heads, flanges, closure studs, nozzles and safe ends, penetrations, attachments with vessel internals, support skirt, and stabilizer brackets. The reactor internal components that are within the scope of license renewal are the core shroud and its support, access hole cover, core spray line and spargers, core support plate and top guide, jet pump assemblies, orificed fuel support, control rod drive housing stub tubes, and guide tubes. The materials for the reactor internal components are stainless steels and nickel-based alloys. The RPVs for Plant Peach Bottom Units 2 and 3 were fabricated by Babcock &Wilcox. The intended functions for the RPV are to provide a fission product barrier and pressure barrier, and to provide structural support for the core and other vessel internal components.

The reactor vessel is located inside the primary containment building. The internal environment of the RPV is coolant water and saturated steam. Coolant water is normally at about 278 °C

(533 °F) and 7.28 MPa (1055 psia) during plant operation. Water quality is maintained within specified limits. During plant shutdown conditions, the coolant temperature in the RPV can be as low as 21 °C (70 °F).

3.1.1.1.1 Aging Effects

The applicant reviews the industry experience (e.g., NRC information notices, generic letters, and bulletins) and the Peach Bottom operating experience (e.g., plant maintenance history, modifications, nonconformance reports, and licensee event reports) and identified the aging effects, component intended functions, environment, and materials for each group of components of the reactor pressure vessel and internals in Tables 3.1-1 of the LRA.

The applicant identified the following aging effects for the reactor pressure vessel and internals:

- cracking due to stress corrosion cracking and cyclic loading
- loss of material for low-alloy steel components
- cumulative fatigue damage
- loss of fracture toughness due to neutron embrittlement of beltline materials

3.1.1.1.2 Aging Management Programs

The applicant identified the following five aging management programs for the reactor pressure vessel and internals:

- Reactor coolant system chemistry
- ISI program
- Reactor pressure vessel and internals ISI program
- Reactor materials surveillance program
- Fatigue management activities

3.1.1.2 Staff Evaluation

The applicant describes its AMR for the reactor pressure vessel and internals in Section 3.1 of the LRA. The staff reviewed this section to determine whether the applicant has identified all the applicable aging effects for components in this system and demonstrated that the effects of aging on the components will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.1.1.2.1 Effects of Aging

The aging effects for the reactor pressure vessel and internals are as follows:

- cracking due to stress corrosion cracking and cyclic loading
- loss of material for low-alloy steel components
- cumulative fatigue damage
- loss of fracture toughness due to neutron and thermal embrittlement

Cracking

Core shroud cracking was first discovered in an overseas BWR in 1990. Subsequently, visual (VT) and ultrasonic (UT) examination techniques have detected cracking in core shrouds in a number of domestic and overseas BWRs. Crack indications have been found in heat-affected zones of both horizontal and vertical welds. The predominant form of cracking is circumferentially oriented indications located in the heat-affected zones of horizontal welds. Limited cracking has also been observed n vertical welds.

Most of the cracking has been identified as intergranular stress corrosion cracking (IGSCC). Irradiation-assisted stress corrosion cracking (IASCC) has also been observed in the core beltline region (weld H4). The shrouds are fabricated using either Type 304 or Type 304L austenitic stainless steel, and cracking has been detected in core shrouds fabricated from both materials.

Initially, BWR owners were notified of the cracking through GE SILs and RICSILs and NRC information notices 93-79, "Core Shroud Cracking at Beltline Regions Welds in BWRs," and 94-42, and supplement 1, "Cracking in the Lower Region of the Core Shroud in BWRs" . As a result of an increased number of detected shroud cracks, the BWR Owners' Group (BWROG) in April 1994 published topical report GE-NE-523-148-1193, "BWR Core Shroud Evaluation." This report provided a conservative, generic screening methodology for evaluating core shroud flaw indications on a plant-specific basis.

In July 1994, the NRC issued Generic Letter (GL) 94-03, "Intergranular Stress Corrosion Cracking of Core Shrouds in Boiling Water Reactors," which required all BWR licensees to inspect their core shrouds at the next scheduled refueling outage. A plant-specific safety evaluation was also required to support continued operation of the plant until the inspections could be performed.

In response to GL 94-03, flaw acceptance criteria for horizontal welds in unrepaired shrouds were submitted to NRC in reports "BWR Core Shroud Inspection and Flaw Evaluation Guidelines," September 2, 1994, and "BWR Core Shroud Inspection and Flaw Evaluation Guidelines," Rev. 1, March 1995. The results of the NRC review of these documents were presented in safety evaluation reports issued on December 28, 1994, and June 16, 1995, respectively. These guidelines grouped core shrouds into three categories (A, B, or C) based on the expected susceptibility to cracking.

The basis for defining the core shroud categories is summarized in Appendix B of the LRA. Welds in Category A core shrouds (those judged unlikely to experience cracking) were exempted from inspection. For Category B shrouds (those judged mildly susceptible to cracking), a sample of horizontal welds (H3, H4, H5, and H7) were required to be inspected. For Category C shrouds (those judged to have potential for significant cracking), all horizontal welds (H1 through H7, inclusive) were required to be inspected. The inspection scope for each weld in Category B and C core shrouds was to cover sufficient weld length to ensure adequate structural integrity.

All vessel internals and attachment welds that are within the scope of license renewal and fabricated from austenitic stainless steel and nickel-based alloys are subject to stress corrosion cracking. The staff-approved BWRVIP reports (i.e., BWRVIP -18, -25, -26, -27, -38, -41, -47,

-48, and -49) support this identification of cracking as an aging effect for these vessel internals and attachment welds.

Cracking due to stress corrosion cracking is an aging effect for vessel closure studs. This identification of cracking as an aging effect is supported by the industry experience reported in Section XI.M3, “Reactor Head Closure Studs," of NUREG-1801, "Generic Aging Lessons Learned (GALL) Report."

Cracking due to cyclic loading is an aging effect for low-alloy steel feedwater nozzles. Generic Letter 81-11,” Crack Growth Analysis to Demonstrate Conformance to the Intent of NUREG-0619, ‘BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking,’” supports this identification of cracking as an aging effect. The control rod drive return line nozzles at Plant Peach Bottom Units 1 and 2 are capped; therefore, these nozzles are not susceptible to cracking due to cyclic loading.

The low-alloy steel vessel shells are not subject to stress corrosion cracking. BWRVIP-05, “BWR Reactor Pressure Vessel Shell Weld Inspection Recommendations,” and BWRVIP-60, “Evaluation of Crack Growth in BWR Low-Alloy Steel RPV Internals,” indicate that even if cracks emanate from the vessel cladding, they are not expected to propagate into the low-alloy steel of the reactor vessel. BWRVIP-05 and BWRVIP-60 have been reviewed and approved by the staff.

Loss of Material

Loss of material has been identified as an aging effect for the top head of the reactor pressure vessel. Loss of material as an aging effect has not been identified for any component of the reactor pressure vessel and vessel internals. Loss of material was evaluated in BWRVIP-74. The staff agrees with this identification, because loss of material was evaluated as part of the BWRVIP program and the only reactor pressure vessel and internals component that was subject to loss of material was the top head of the reactor pressure vessel.

Cumulative Fatigue Damage

Cumulative fatigue damage is an aging effect for the reactor pressure vessel feedwater nozzle, “other nozzles,” and the support skirt. In response to RAI 3.1-2 inquiring about the definition of "other nozzles," the applicant submitted the following information. The term "other nozzles" includes both nozzles and safe ends with a design-basis-predicted 40-year CUF of 0.4 or greater.

Table 3.1-1 of the LRA does not identify cumulative fatigue damage as an aging effect for vessel flanges and stabilizer brackets. Table 3-1 of BWRVIP-74, “BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines,” however, identifies cumulative fatigue damage as an aging effect for these two components. RAI 3.1-2 requested a justification for not identifying cumulative fatigue damage as an aging effect for these two components. In response, the applicant stated that the CUFs for these components are low and, therefore, Table 3.1-1 of the LRA does not identify cumulative fatigue damage as an aging effect for these components. For a 40-year life, the CUF for the Peach Bottom Units 2 and 3 stabilizer brackets is 0.17, and for vessel flanges, it is 0.0. The staff finds the applicant's response acceptable because the CUF projected for the license renewal period for these components is low.

BWRVIP-74, “BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines” determined that cumulative fatigue damage of the vessel shell and closure head is not an aging effect requiring management. This conclusion is justified because the applicable fatigue usage factors for the vessel shell, according to BWRVIP-74, are very low in comparison to other RPV locations.

Loss of Fracture Toughness Due to Neutron and Thermal Embrittlement

Low-alloy steel components in the reactor pressure vessel may be susceptible to loss of fracture toughness due to neutron embrittlement. Loss of fracture toughness due to neutron embrittlement is potentially significant for vessel materials in the beltline region. The beltline region of reactor vessel, according to Appendix G to 10 CFR Part 50, is the region of the reactor that directly surrounds the effective height of the active core and adjacent regions of the reactor vessel that are predicted to experience sufficient neutron radiation damage to be considered in the selection of the most limiting material with regard to radiation damage. Appendix H to 10 CFR Part 50 states that neutron irradiation embrittlement becomes significant at a neutron fluence greater than 10^{17} n/cm^2 (E>1Mev). BWRVIP-74, "BWR Vessel Internals Project—BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines," considers 10^{17} n/cm^2 (E>1Mev) as the threshold fluence for radiation embrittlement and identifies vessel shell materials (i.e., base metal, weld metal, and heat-affected zone) in the beltline region being susceptible to radiation embrittlement. In addition, Table 3-1 of BWRVIP-74 identifies water level instrument nozzles made of low-alloy steel as susceptible to radiation embrittlement. According to Table 2-1 of BWRVIP-49, "BWR Vessel and Internals Project—Instrument Penetration Inspection and Flaw Evaluation Guidelines," the water level instrument nozzles at Peach Bottom Units 2 and 3 are made of Type 304 stainless steel. Therefore, these nozzles are not susceptible to radiation embrittlement.

CASS components in the reactor pressure vessel and vessel internals may be susceptible to loss of fracture toughness due to the synergistic effects of thermal and neutron embrittlement. An evaluation of the loss of fracture toughness for CASS components is presented in a May 19, 2000, NRC letter. The staff evaluation in this letter indicates that the susceptibility to thermal aging embrittlement of CASS components is dependent upon the casting method, molybdenum content, and ferrite content. For low-molybdenum (0.5 wt.% max) steels, only static-cast steels with > 20% ferrite are potentially susceptible to thermal aging embrittlement. For high-molybdenum (2.0 to 3.0 wt.%) steels, static-cast steels with >14% ferrite are potentially susceptible to thermal aging embrittlement. In the susceptibility screening method, ferrite content is calculated by using the Hull’s equivalent factors (described in NUREG/CR-4513, Rev. 1) or a method producing an equivalent level of accuracy (±6% deviation between measured and calculated values).

Table 2.3.1-1 of the LRA indicates that jet pump assemblies and fuel supports containing CASS components are within the scope of license renewal. The Plant Peach Bottom fuel supports bear the weight of the fuel assemblies and distribute core flow to the fuel assemblies. 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, 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 aging embrittlement.

For all CASS components that are susceptible to significant thermal aging embrittlement, the applicant may perform a flaw tolerance analysis. The flaw tolerance analysis should follow the methodology and criteria in Code Case N-481.

In RAI 3.1-4, the staff requested the applicant to identify the CASS components that will not satisfy the above-specified thermal embrittlement susceptibility criteria and will require a flaw tolerance analysis. The applicant responded that the jet pump assembly and orificed fuel supports were manufactured to the low-molybdenum 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. The maximum calculated delta ferrite percentage (based on ASTM A800 and the certified material test reports) of any of the statically cast components is below 20%. Therefore, according to criteria stated in the NRC letter mentioned above, these components are not susceptible to thermal aging for statically or centrifugally cast components. The staff finds the applicant's response to RAI 3.1-4 acceptable.

Appendix H to 10 CFR Part 50 indicates that neutron irradiation embrittlement becomes significant at neutron fluence greater than 10^{17} n/cm^2 (E>1Mev). Therefore, the CASS components in the jet pump assemblies and CASS fuel supports are also susceptible to neutron irradiation embrittlement if these components experience neutron fluence greater than 10^{17} n/cm^2. 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. In RAI 3.1-5, the staff requested the applicant to describe an aging management program to confirm that the CASS jet pump assembly components and fuel supports are not susceptible to cracking. In its response the applicant stated that 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 for the CASS components later in life. The applicant further stated that the BWRVIP guidelines are implemented at PBAPS through the Reactor Pressure Vessel and Internals ISI program, which is an augmentation of the PBAPS 10-year ISI program. In the PBAPS LRA, Appendix B.2.7, "RPV and Internals ISI Program," credits BWRVIP-41 for inspection of the jet pump assembly. For the case of the orificed fuel support (OFS), the applicant referred to BWRVIP-06, "Safety Assessment of BWR Internals," Section 2.9, which states that 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 that "visual inspections at seven facilities have found no indications of cracking in OFS castings." Therefore, no aging management program is necessary to manage the effects of irradiation on the orificed fuel supports. The staff finds the applicant's response to RAI 3.1-5 acceptable because the BWRVIP program addresses CASS jet pump assembly and OFS components.

Void Swelling

According to EPRI technical report TR-107521, "Generic License Renewal Technical Issues Summary," April 1998, void swelling is a gradual increase in dimension of an austenitic stainless steel part as a result of fast neutron irradiation. EPRI TR-107521 cites sources with conflicting results on predicting the extent of possible void swelling for light-water reactor conditions. One source predicts swelling as great as 14% for PWR baffle-former assemblies over a 40-year plant lifetime, whereas results from another source indicate that swelling would be less than 3% for the most highly irradiated sections of the internals at 60 years. The issue is the impact of change of dimension due to void swelling on the ability of the reactor vessel internals to perform their intended functions. Swelling of the reactor vessel internals could potentially impact the ability to insert control element assemblies and to maintain proper coolant flow distribution characteristics.

The applicant has not identified cracking or change in dimensions as an aging effect caused by void swelling. In response to RAI 3.1-3, the applicant submitted the following justification for excluding these effects for the reactor pressure vessel internals. EPRI TR-107521 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 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 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 suggest that void swelling is a significant issue. The lowest temperature for which this phenomenon is conjectured to occur is 300 °C (572 °F), which is higher than the internals of 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 adequate to manage aging. The BWRVIP program that is implemented at Peach Bottom is adequate to address aging of the internals. The staff finds this response acceptable because the BWRVIP program for BWR internals addresses the key aspects of the internals components and provides inspection criteria where adequate to manage this aging effect.

3.1.1.2.2 Aging Management Programs

The aging management programs for the reactor pressure vessel and internals are identified in Section 3.1.1.1 of this SER. These programs are reviewed by the staff in the following sections of the SER and found to be acceptable:

- Reactor Coolant System Chemistry Program, Section 3.0.3.2
- ISI Program, Section 3.0.3.6
- Reactor Pressure Vessel and Internals ISI Program, Section 3.0.3.9
- Reactor Materials Surveillance Program, Section 3.0.3.20
- Fatigue Management Activities, Section 4.3

The reactor coolant system chemistry, ISI, reactor pressure vessel and internals ISI, and reactor materials surveillance programs are credited with managing the aging effects of several components in various different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and, found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

3.1.1.3 Conclusions

The staff has reviewed the aging effects for the reactor pressure vessel and internals presented in Section 3.1 of the LRA and the AMPs presented in Sections B.1.2, B.1.8, B.1.12, and B.2.7 of Appendix B of the LRA. On the basis of the review, the staff concludes that the applicant has demonstrated that these AMPs adequately manage the effects of aging associated with RPV and internals components that are within the scope of license renewal so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2 Fuel Assemblies

3.1.2.1 Technical Information in the Application

The fuel assemblies are assemblies of fissionable material that can be arranged in a critical array. Each assembly must be capable of transferring the generated fission heat to the circulating coolant water while maintaining structural integrity and containing the fission products. The intended function of fuel assemblies is to provide a fission product barrier. The fuel cladding is the primary fission product barrier. The external environment of the fuel assemblies is reactor coolant water. The fuel assembly experiences the complete range of reactor coolant pressures and temperatures. Since the fuel assemblies are subject to replacement within a specified time period in accordance with 10 CFR 54.21(a)(1)(ii), the fuel assemblies do not require aging management review.

3.1.2.2 Staff Evaluation

The staff finds the applicant's conclusion to be acceptable because it is consistent with 10 CFR 54.21(a)(1)(ii).

3.1.2.3 Conclusions

On the basis of the review of the information presented in the LRA, the staff concludes that the applicant has adequately determined that the fuel assemblies do not require an aging management review.

3.1.3 Reactor Pressure Vessel Instrumentation System

3.1.3.1 Technical Information in the Application

The reactor pressure vessel instrumentation system consists of components utilized for flow, water level, pressure, and temperature measurements required for the operation of the reactor under normal, transient, shutdown, and accident conditions. The major components of the instrumentation system that are within the scope of license renewal are piping (including fittings), tubing, valve bodies, restricting orifices, and condensing chambers. The materials of the instrumentation system components are stainless steel and carbon steel. The intended function of the instrumentation system components is to provide a barrier to pressure. The internal environments of the instrumentation system components are either steam or reactor coolant. The external environment is the sheltered environment.

3.1.3.1.1 Aging Effects

The applicant reviewed the industry experience (e.g., NRC information notices, generic letters, and bulletins) and the Peach Bottom operating experience (e.g., plant maintenance history, modifications, nonconformance reports, and licensee event reports) and identified the aging effects, component functions, environment, and materials for each component group in the reactor pressure vessel instrumentation system in Table 3.1-3 of the LRA.

The applicant identified the following aging effects for the reactor vessel instrumentation system:

- cracking for stainless steel components
- loss of material for carbon steel and stainless steel components

3.1.3.1.2 Aging Management Programs

The applicant identified the following two aging management programs for the reactor pressure vessel instrumentation system:

- Reactor Coolant Chemistry Program
- ISI Program

The Reactor Coolant System Chemistry Program and the ISI Program are credited with managing the aging effects of several components in various different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and, found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

3.1.3.2 Staff Evaluation

The applicant describes its AMR for the reactor pressure vessel instrumentation system in Section 3.1 of the LRA. The staff reviewed this section to determine whether the applicant has identified all the applicable aging effects for components in these systems and demonstrated that the effects of aging on the components will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.1.3.2.1 Effects of Aging

The aging effects for the reactor pressure vessel instrumentation system are as follows:

- cracking of stainless steel components
- loss of material of carbon steel and stainless steel components

<u>Cracking</u>

The reactor pressure vessel instrumentation system stainless steel components exposed to the reactor coolant water or steam environment are susceptible to cracking. The affected components include pipe (including fitting), tubing, valve bodies, condensing chamber, and restricting orifice. However, the applicant does not identify whether the cracking results from stress corrosion cracking or thermal fatigue, and whether butt-welded piping and components less than 4 inches in diameter are susceptible to cracking. The staff issued RAI 3.1.3.1-7 requesting this information. The applicant submitted a response to the RAI in a teleconference call between the staff and representatives of Exelon to clarify information presented in the LRA pertaining to Sections 3.1 and 4.1. (See response to RAI 3.1.3.1-7 in a telephone conversation summary, "Telecommunication with EXELON Generating Company to Discuss Information in Sections 3.1 and 4.1 of the Peach Bottom License Renewal Application," dated March 13, 2002.) The applicant stated that the RPV instrumentation system is not prone to sudden changes in temperature that could cause high cycle fatigue and, therefore, is not susceptible to thermal fatigue resulting from turbulent penetration or thermal stratification.

The applicant submitted the following information related to stress corrosion cracking of the stainless steel instrumentation piping. The RPV instrumentation system piping is 2 inches or less in diameter and does not have any butt weld connections. Most of the piping in this system is 1 inch or less. The aging management activities identified for managing cracking due to SCC are Reactor Coolant System Chemistry (Appendix B.1.2) and ISI (Appendix B.1.8) as defined in PBAPS LRA Table 3.1-3. The ISI program requires system hydrotesting for this system in accordance with Section XI of the ASME Code. The applicant believes that these two programs are adequate in managing cracking due to SCC in 2 inch-or-less-diameter reactor coolant pressure boundary piping. The staff found the applicant’s response not sufficient because it lacked adequate details for piping with a diameter greater than 2 inches and less than 4 inches. In response to RAI 3.1-6 requesting this information, the applicant stated that all Class 1 butt-welded piping and components that are less than 4 inches but greater than 2 inches in diameter and within the scope of license renewal are made of carbon steel and not stainless steel. The staff finds this response acceptable because carbon steel components in BWR reactor water environments are not susceptible to stress corrosion cracking.

The application does not identify the aging effect of cracking due to stress corrosion cracking and cyclic loading for valve closure bolting in the reactor pressure vessel instrumentation 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. In RAI 3.1-1, the staff requested the applicant to take into account the above information and review industry and plant experience to assess whether these aging effects are applicable for valve closure bolting in the reactor pressure vessel instrumentation system. If such an aging effect is present, the applicant should submit an aging management program to manage cracking in valve closure bolting in the reactor pressure vessel instrumentation system. In response to RAI 3.1-1, the applicant provided the following justification for why cracking due to SCC is not considered an applicable aging effect for valve closure bolting in the reactor pressure vessel instrumentation system: 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 closure bolting. In evaluating the susceptibility of bolting material, the applicant did not address the effect of the humid environment within containment and the possibility of high yield strength (>150 ksi) for bolting material. **This is part of Open Item 3.1.3.2.1-1.** Additional parts of this open item are discussed below under the loss of material and loss of preload in Section 3.1.4.2.1.

Loss of Material

The reactor pressure vessel instrumentation system components are susceptible to loss of material due to their exposure to reactor coolant water or steam. The majority of these components are fabricated from stainless steel. They include piping, tubing, and valve bodies (including valve bonnets), condensing chambers, and restricting orifices. One piping component is made of carbon steel and is exposed to a steam environment. In response to RAI 3.1-8, the applicant stated that loss of material in the carbon steel piping includes the loss due to galvanic corrosion. The applicant identifies the RCS chemistry program to mitigate this effect and the ISI program, which includes periodic hydrostatic tests. However, these pressure tests are not adequate to confirm the effectiveness of the RCS chemistry program to prevent loss of material in this component. In response to RAI 3.1-7 requesting a description of an aging management program to confirm the effectiveness of the RCS chemistry program in mitigating the aging effect of loss of material, the applicant stated that the stainless steel components exposed to reactor coolant or steam environments are not susceptible to significant loss of material. Plant-specific and industry experience does not indicate a problem due to loss of material in these stainless steel components. Therefore, the RCS chemistry and ISI programs are adequate to manage loss of material in these stainless steel components. The staff finds this response acceptable for the stainless steel components. However, carbon steel is more susceptible to loss of material than stainless steel. The ISI program will not detect the loss of material on the inside of the carbon steel pipe; therefore is not adequate to assess the effectiveness of the RCS chemistry program to mitigate loss of material in carbon steel components. Therefore, the applicant needs to provide periodic inspections to confirm the effectiveness of the RCS chemistry program for carbon steel components. **This is part of Open Item 3.1.3.2.1-1.**

The applicant has not identified loss of material as an aging effect for valve closure bolting in the reactor pressure vessel instrumentation system. In response to RAI 3.1-1, the applicant stated that 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 a component. On the basis of this guideline, PBAPS LRA did not include it as a line item under component groups, although an AMR was performed for the bolting exposed to the sheltered environment. The AMR did not identify loss of material as an aging effect because several mitigative actions are in place to avoid direct contact between a continuous moisture source and the bolting. These actions include grease coating of bolting during installation, use of antisweat insulation for bolting where the operating temperature is below ambient, and timely repair of any system leakage. However, the applicant does not identify any activities to assess and maintain the effectiveness of grease coating and antisweat insulation. **This is part of Open Item 3.1.3.2.1-1.**

Loss of Preload

The applicant does not identify loss of preload as an aging effect for valve closure bolting in the reactor pressure vessel instrumentation system. In response to RAI 3.1-1 requesting information about whether a review of industry experience and plant-specific experience indicates the loss of preload as an aging effect for valve closure bolting, the applicant stated that loss-of-preload events are due to human errors and, therefore, should be excluded from an aging management review. In support of this position, the applicant cites the June 5, 1998, NRC letter from C.I. Grimes to D. Walters of NEI on the subject of license renewal Issue No. 98-0013, "Degradation Induced Human Activities." The letter concludes that degradation events induced by human activities need not be considered as a separate aging effect and should be excluded from an aging management review. The staff does not agree with the applicant's response. Loss of preload can be caused by factors other than degradation induced by human activities, such as vibration, cyclic loading, gasket creep, and stress relaxation. **This is part of Open Item 3.1.3.2.1-1.**

3.1.3.2.2 Aging Management Programs

The aging management programs for the reactor pressure vessel instrumentation system are identified in Section 3.1.3.1 of this SER. These programs are reviewed by the staff in the following sections of the SER.

- Reactor Coolant Chemistry Program, Section 3.0.3.2
- ISI Program, Section 3.0.3.6

3.1.3.3 Conclusions

The staff has reviewed the reactor pressure vessel instrumentation system aging effects presented in Section 3.1 of the LRA and the two AMPs presented in Sections B.1.2 and B.1.8 of Appendix B of the LRA. On the basis of the review, except for **Open Item 3.1.3.2.1-1**, the staff concludes that the applicant has demonstrated that these AMPs adequately manage the effects of aging associated with RPV instrumentation system components that are within the scope of license renewal so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.4 Reactor Recirculation System

3.1.4.1 Technical Information in the Application

The reactor recirculation system (RRS) maintains the reactor coolant pressure boundary during normal operation, transient, shutdown, and accident conditions to prevent the release of radioactive liquid and gas. The RRS is also one of the two core reactivity control systems. The materials of the RRS components are stainless steel and carbon steel. The RRS consists of two parallel loops, each consisting of a recirculation pump, suction and discharge valves, piping, piping supports, and piping restraints. The RRS provides flowpaths out of the reactor pressure vessel for RHR and RWCU systems and into the vessel for RHR shutdown cooling and low-pressure coolant injection.

3.1.4.1.1 Aging Effects

The applicant reviews the industry experience (e.g., NRC information notices, generic letters, and bulletins) and the Plant Peach Bottom operating experience (e.g., plant maintenance history, modifications, nonconformance reports, and licensee event reports) and identified the aging effects, component functions, environment, and materials for each component group in the reactor recirculation system in Table 3.1-4 of the LRA.

The applicant identified the following aging effects for the reactor recirculation system:

- cracking for stainless steel components
- loss of material for carbon steel and stainless steel components
- loss of fracture toughness due to thermal aging of cast stainless steel pump casings

3.1.4.1.2 Aging Management Programs

The applicant identified the following two aging management programs for the reactor recirculation system:

- RCS Chemistry Program, Section 3.0.3.2
- ISI Program, Section 3.0.3.6

3.1.4.2 Staff Evaluation

The applicant describes its AMR for the reactor recirculation system in Section 3.1 of the LRA. The staff reviewed this section to determine whether the applicant has identified all the applicable aging effects for components in these systems and demonstrated that the effects of aging on the components will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.1.4.2.1 Effects of Aging

The aging effects for the reactor recirculation system are as follows:

- cracking due to stress corrosion cracking for stainless steel components
- loss of material for carbon steel and stainless steel components
- cumulative fatigue damage (an additional aging effect discussed below and in TLAA Section 4.3)
- loss of fracture toughness due to thermal aging of cast austenitic stainless steel pump casings

Cracking

The applicant identified cracking as an applicable aging effect for the recirculation system austenitic stainless steel components (piping, tubing, valve bodies, flow elements, thermowells, and restricting orifice) but not cast stainless steel components exposed to reactor coolant water. According to NUREG-0313, Rev. 2, a CASS component is susceptible to stress corrosion cracking if the carbon content is greater than 0.035% or the ferrite content less than

7.5%. In a statically cast CASS component (i.e., pump casing), the ferrite distribution is not uniform and could be below 7.5% at some locations on the inside surface of the component. In addition, if the ferrite content of the weld metal used to repair the inside surface of the pump casing is less than 7.5%, the pump casing is susceptible to stress corrosion cracking. In RAI 3.1-10, the staff requested the applicant to provide technical justification for not including cracking as an aging effect for the CASS pump casings in the reactor recirculation system. In response, the applicant stated that the aging effect of cracking was inadvertently excluded from LRA Table 3.1-4. In the first row of Table 3.1-4, the Casting and Forging component group should include both pump casings and valve bodies. The aging effect of cracking will be managed by the RCS Chemistry and ISI Programs. The staff finds the applicant's response acceptable because the applicant has identified cracking as an aging effect for pump casings and valve bodies and identified the RCS Chemistry and ISI Programs as the aging management program for these components.

The applicant does not identify cracking as an aging effect for any unisolable sections of piping connected to the RCS that can be subjected to stresses from temperature stratification or temperature oscillations induced by leaking valves. In RAI 3.1-11, the staff requested information about whether the applicant, in response to NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems," identified any unisolable sections of piping connected to the RCS that can be subjected to stresses from temperature stratification or temperature oscillations induced by leaking valves. The staff also requested the applicant to present an evaluation of the BWR industry-wide response to NRC Bulletin 88-08. In response to RAI 3.1-11, the applicant stated that in the Exelon response to NRC Bulletin 88-08 (submitted to the NRC by letter dated September 16, 1988), the design of the Peach Bottom station does not contain any unisolable sections of piping that are potentially subjected 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 subjected to stresses of the type defined in the bulletin. The staff finds the applicant's response acceptable.

The application does not identify the aging effect of cracking due to stress corrosion cracking and cyclic loading for closure bolting of the recirculation pumps and valves in the recirculation 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. This issue is discussed in greater detail in Section 3.1.3.2.1 of the SER. **This is part of Open Item 3.1.3.2.1-1**.

Loss of Material

The applicant has identified loss of material due to corrosion as an aging effect for the reactor recirculation system carbon steel and stainless steel components exposed to reactor coolant water. The components include valve bodies, pipe and tubing, flow elements, thermowells, and restricting orifice. The staff agrees that carbon steel components exposed to reactor coolant water and stainless steel components in stagnant reactor coolant water could be susceptible to loss of material.

The applicant does not identify loss of material due to corrosion as an aging effect for recirculation pump closure bolting and valve closure bolting in the reactor recirculation system. Lost of material is discussed in greater detail in Section 3.1.3.2.1 of the SER. **This is part of Open Item 3.1.3.2.1-1**.

The applicant does not identify loss of material due to wear as an aging effect for recirculation pump closure bolting and valve closure bolting in the reactor recirculation system. In response to RAI 3.1-1, the applicant stated that wear is caused by vibration and prying loads, both of which are event-related mechanisms. Therefore, loss of material due to wear should be excluded from an aging management review. The staff disagrees because vibrations and prying loads that can occur during normal operation and maintenance activities can cause loss of material due to wear. **This is part of Open Item 3.1.3.2.1-1.**

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. In RAI 3.1-8(b), the staff requested the applicant to identify whether the carbon steel piping of the reactor recirculation system is connected to stainless steel components, and if so, then state whether the aging effect of loss of material includes galvanic corrosion. Since the applicant has identified the RCS chemistry program to mitigate this aging effect, the staff further requested the applicant to describe an aging management program to confirm the effectiveness of the RCS chemistry program to prevent loss of material from galvanic corrosion. In response, the applicant states that the only carbon steel components 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. However, the staff does not consider the hydrostatic pressure tests adequate because it will not detect the loss of material on the inside of the carbon steel pipe, therefor it will not confirm the effectiveness of the RCS chemistry program to prevent loss of material in these components. **This is part of Open Item 3.1.3.2.1-1.**

<u>Cumulative Fatigue Damage</u>

Piping; the recirculation pump casing, cover, seal flange and closure bolting; and valve bodies, bonnets, and closure bolting in the reactor recirculation system are susceptible to cumulative fatigue damage due to plant heatup, cooldown, and other operational transients. However, the applicant did not identify cumulative fatigue damage as an aging effect for any of the components in the reactor recirculation system. In RAI 3.1-12, the staff requested the applicant to present 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. In response to RAI 3.1-12, the applicant stated that cumulative fatigue damage is addressed in

TLAA Section 4.3 of the LRA. Cumulative fatigue for reactor recirculation piping designed to ASME Section III Class 1 requirements is addressed in the TLAA Section 4.3.3.1. Although reactor recirculation system piping designed to the requirements of ANSI B31.1 does not require explicit fatigue analyses, PBAPS LRA Section 4.3.3.2 addresses piping and component fatigue and thermal cycles for piping designed to the requirements of ANSI B31.1. The staff's review of this TLAA is discussed in Section 4.3 of this SER.

Loss of Fracture Toughness

The applicant has identified the loss of fracture toughness due to thermal aging embrittlement as an applicable aging effect for the CASS pump casing of the recirculation pump. The staff agrees that CASS materials are susceptible to thermal aging embrittlement.

Loss of Preload

The applicant does not identify loss of preload as an aging effect for recirculation pump closure bolting and valve closure bolting in the reactor recirculation system. This issue is discussed in greater detail in Section 3.1.3.2.1 of this SER. **This is part of Open Item 3.1.3.2.1-1**.

3.1.4.2.2 Aging Management Programs

The aging management programs for the reactor recirculation system are identified in Section 3.1.4.1 of this SER. These programs are reviewed by the staff in the following sections of the SER.

- RCS Chemistry Program, Section 3.0.3.2
- ISI Program, Section 3.0.3.6

3.1.4.3 Conclusions

The staff has reviewed the reactor pressure vessel instrumentation system aging effects presented in Section 3.1 of the LRA and the AMPs presented in Sections B.1.2 and B.1.8 of Appendix B of the LRA. On the basis of the review, with the exception of Open Item 3.1.3.2.1-1, the staff concludes that the applicant has demonstrated that these AMPs adequately manage the effects of aging associated with RPV instrumentation system components that are within the scope of license renewal so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2 Aging Management of Engineered Safety Features Systems

In Section 3.2 of the LRA the applicant describes its aging management reviews (AMRs) for the engineered safety features (ESF) systems. The staff reviewed Section 3.2 to determine whether the applicant has provided sufficient information to demonstrate that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation, in accordance with 10 CFR

54.21(a)(3) for the ESF system structures and components (SCs) that are determined to be within the scope of license renewal and subject to AMRs.

The Peach Bottom ESF systems include the following systems:

- high-pressure coolant injection system (HPCI)
- core spray system (CS)
- primary containment isolation system (PCIS)
- reactor core isolation cooling system (RCIC)
- residual heat removal system (RHR)
- containment atmosphere control and dilution system (CACDS)
- standby gas treatment system (SGTS)
- secondary containment system (SCS)

The design descriptions and safety functions for these ESF systems are sufficiently described in Sections 2.3.2.1, 2.3.2.2, 2.3.2.3, 2.3.2.4, 2.3.2.5, 2.3.2.6, 2.3.2.7, and 2.3.2.8 of the application, respectively. The applicant provides its AMR results for these ESF systems in Sections 3.2.1, 3.2.2, 3.2.3, 3.2.4, 3.2.5, 3.2.6, 3.2.7, and 3.2.8 and Tables 3.2-1, 3.2-2, 3.2-3, 3.2-4, 3.2-5, 3.2-6, 3.2-7, and 3.2-8 of the application, respectively. The staff's AMR evaluations of these ESF systems are given in Sections 3.2.1, 3.2.2, 3.2.3, 3.2.4, 3.2.5, 3.2.6, 3.2.7 and 3.2.8 of this SER, respectively.

3.2.1 High-pressure Coolant Injection

3.2.1.1 Technical Information in the Application

The applicant describes its AMRs of the passive HPCI components within the scope of license renewal in Section 3.2.1 and Table 3.2-1 of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant demonstrated that the effects of aging associated with the HPCI will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3). A complete list of the HPCI components requiring AMRs and the component intended functions is provided in Table 3.2-1 of the application.

3.2.1.1.1 Aging Effects

In Table 3.2-1 of the application, the applicant identifies the following components that are subject to AMRs: piping, piping specialties (i.e., thermowells, tubing, pumps, valves, fittings, tanks, steam traps, rupture discs, spargers, restricting orifices, flow elements, and suction strainers), valve bodies, pump casings, filter bodies, turbine casing, flex hose, and heat exchangers (HX) and their subcomponents (i.e., HPCI gland seals, coolers, coils, tubes, tubesheets, frames, channels, and shells).

In this table, the applicant identifies that the specific components are fabricated from the following materials:

- carbon steel
- stainless steel
- cast iron
- galvanized carbon steel

- aluminum
- copper, bronze, and brass alloys (including admiralty brass)
- neoprene and other rubber materials

The applicant identifies that these components are exposed to one or more of the following environments:

- condensate storage water
- lubricating oil
- reactor coolant
- sheltered environment
- steam
- torus-grade water
- ventilation atmosphere
- wetted gas
- raw water

The applicant describes the environmental conditions for these environments in Section 3.0 of the application. The applicant identifies the following aging effects as possibly applicable to the HPCI components:

- loss of material
- cracking
- heat transfer reduction
- flow blockages

3.2.1.1.2 Aging Management Programs

The applicant credits the following programs and activities for managing the aging effects attributed to these components:

- demineralized water and condensate storage tank chemistry activities
- reactor coolant system chemistry activities
- inservice inspection program (ISI)
- torus water chemistry activities
- torus piping inspection activities
- heat exchanger inspection activities
- HPCI and RCIC turbine inspection
- lubricating and fuel oil quality testing activities
- Generic Letter 89-13 activities
- flow-accelerated corrosion program

3.2.1.2 Staff Evaluation

The staff reviewed the component groups, intended functions, environments, materials of construction, aging effects, and aging management activities for the components of the HPCI system in Table 3.2-1 of the LRA to determine whether the applicant has demonstrated that the effects of aging will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.1.2.1 Effects of Aging

<u>Aging Effects for the Surfaces of HPCI Components Exposed to Liquid Environments</u>

HPCI includes piping, pipe fittings and specialties, branch connections, pumps, valves, and heat exchanger components that are exposed to liquid environments, including the reactor coolant, condensate storage water, torus-grade water, and lubricating oil environments. The majority of these components are made from stainless or carbon/low-alloy steel materials, although some of the HPCI components are fabricated from either copper/bronze/brass alloys, cast iron, or aluminum materials. The applicant identified the following aging effects as applicable to the HPCI components that are exposed to liquid environments:

- loss of material in piping, pump, valve, and vessel components that are fabricated from carbon steel, cast iron, brass, brass alloys, bronze, and copper alloys and exposed to reactor coolant, torus-grade water, raw water, condensate storage water, and lubricating oil

- loss of material and cracking in stainless steel piping, pump, valve, and vessel components exposed to condensate storage water and torus-grade water, and loss of material in stainless steel piping components exposed to lubricating oil

- loss of material, cracking, and loss of heat transfer function in admiralty brass and carbon steel heat exchanger components that are exposed to lubricating oil or condensate storage water

- loss of material, cracking and flow blockage of the copper HPCI pump room cooling coil tubes that are exposed to raw water

- loss of properties of neoprene and rubber in flex hoses exposed to lubricating oil

Stainless steel materials are normally designed to resist the effects of corrosion in liquid environments; however, they may become susceptible to loss of material in stagnant or creviced areas where pitting or creviced-induced corrosion may occur. Industry experience and experimental data have demonstrated that austenitic stainless steel materials may be susceptible to stress corrosion cracking when exposed to specific environments. Elevated levels of oxidizing impurity species (oxygen, sulfates, halides, etc.) increase the potential for these aging effects to occur. Cracking may also occur in stainless steel materials as a result of thermal fatigue. Thermal fatigue of the stainless steel HPCI components is addressed in Section 4.3 of the LRA and evaluated in Section 4.3 of this SER. Based on these considerations, the staff concludes that the applicant's identification of aging effects for the stainless steel HPCI components that are exposed to fluid conditions is acceptable because it is in agreement with Table 3.2-1 of NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," which identifies loss of material and cracking as applicable aging effects for these components.

HPCI also includes a significant number of components that are fabricated from carbon steel (including galvanized steel), low-alloy steel, cast iron, copper, bronze, and brass (including piping, pipe fittings and specialties, branch connections, pump casings, valve bodies, and vessels, and heat exchanger shells, channels, tubesheets, and frames) and are exposed to liquid environments. These environments include the reactor coolant, condensate storage water, torus-grade water, or lubricating oil environments. Loss of material may occur in these materials as a result of general corrosion when the components are exposed to moist oxidizing, aqueous, or vitriolic (oil) environments. Loss of material is therefore an applicable aging effect for the surfaces of carbon steel, low-alloy steel, cast iron, copper, bronze, and brass HPCI components that are exposed to these liquid environments. Identification of loss of material from these components covers the potential for loss of material to occur from the external surfaces of HPCI valve bodies that are exposed to the reactor coolant as a result of postulated leakage. The applicant has adequately identified loss of material as an applicable aging effect for the surfaces of carbon steel, low-alloy steel, cast iron, copper, bronze, and brass HPCI and other ESF components that are exposed to these liquid environments.

With regard to cracking of carbon steel, low-alloy steel, cast iron, copper, bronze, and brass HPCI components, the most common causes of cracking in HPCI components are stress corrosion cracking and thermal fatigue. Thermal fatigue of these components is addressed in Section 4.3 of the LRA and is evaluated in Section 4.3 of this application. Stress corrosion cracking is not normally an issue for carbon steel, low-alloy steel, copper alloy (including bronze and brass) or cast iron pressure boundary components unless the components are highly stressed. The applicant has therefore identified cracking as an applicable effect only for the HPCI and other ESF heat exchanger components that are fabricated from carbon steel, copper or admiralty brass and that are exposed to aqueous or oily environments. The applicability of additional aging effects for the HPCI heat exchangers is discussed further in the two paragraphs that follow. Based on these considerations, the staff concludes that the applicant's identification of aging effects for the HPCI components that are fabricated from carbon steel (including galvanized steel), low-alloy steel, cast iron, copper, bronze, and brass and are exposed to liquid environments is acceptable because it is in agreement with Table 3.2-1 of NUREG-1800, which identifies loss of material and cracking as applicable aging effects for these components.

HPCI includes a number of heat exchanger components, including the HPCI gland seal cooler, HPCI lube oil cooler, and HPCI pump room cooling coils. The shells, frames, tubesheets, channels, and tubes of HPCI heat exchangers (i.e., gland seal cooler, HPCI lube oil cooler, and HPCI pump room cooling coils) serve heat transfer functions in addition to pressure boundary functions. The applicant has identified loss of heat transfer function as an additional applicable effect for the components in the HPCI gland seal coolers and HPCI lube oil coolers that have been analyzed as being necessary for removing heat during postulated accident conditions and that are exposed to condensate storage water or lubricating oil. The applicant did not identify heat transfer reduction as an applicable effect for either the HPCI or the reactor core isolation cooling (RCIC) pump room cooling coils. The staff's evaluation of the applicant's basis for concluding that heat transfer reduction is not an applicable effect for the HPCI and RCIC pump room cooling coils is given in the following two paragraphs.

The designs, materials of fabrication, and environments for the HPCI pump room coolers are similar to those for the CS, RHR, and RCIC pump room cooling coils. The HPCI pump room cooling coils recirculate raw water through the cooling coil tubes to remove excess heat from the sheltered air conditions in the HPCI pump rooms. The components in these cooling coils therefore serve a heat transfer function in addition to the pressure boundary function of the cooling coil tubes. The applicant has determined that cracking, loss of material, and flow blockage are all applicable aging effects for the surfaces of the HPCI pump room cooling coil tubes that are exposed to raw water. The cooling coil tubesheets and frames are fabricated from galvanized carbon steel, the cooling coil fins are fabricated from aluminum, and the cooling coil tubes are fabricated from copper. The fins, frames, and tubesheets are exposed to sheltered air conditions and the copper tubes are exposed to raw water internally and sheltered air externally. In Tables 3.2-2 and 3.2-5 of the application, the applicant provided its corresponding AMRs for the CS and RHR pump room cooling coil components and identified cracking, loss of material, flow blockage, and heat transfer reduction function as applicable effects for the surfaces of the RHR pump room cooling coil tubes that are exposed to raw water and heat transfer reduction function as an applicable aging effect for the RHR pump room coiling coil fins, tubes, tubesheets, and frames that are exposed to sheltered air. Table 3.2-1 of NUREG-1800 identifies biofouling and corrosion products (crud) as applicable to ESF heat exchanger tubes that are exposed to raw water sources. These mechanisms can lead to a loss of heat transfer function in these tubes. The applicant is required under the environmental qualification (EQ) requirements of 10 CFR 50.49 to assure the operability of safety-related electrical components by qualifying the components as capable of operating during the worst-case environmental conditions postulated to occur during a design basis accident. The applicant has performed an EQ analysis of both the HPCI and the RCIC pump rooms for the environmental conditions that are postulated to occur during a postulated design basis accident for the plants and has determined that the HPCI and RCIC pump room cooling coils are not required to maintain the operability of the HPCI and RCIC systems during these events. This provides an acceptable technical basis for concluding that reduction in heat transfer function is not an applicable effect for either the HPCI or the RCIC pump room cooling coil tubes that are exposed to raw water. The staff therefore concludes that the applicant's identification of aging effects for the HPCI and RCIC pump room cooling coil components under liquid conditions is acceptable.

Based on the technical considerations discussed in the previous paragraphs, the staff concludes that the applicant's identification of aging effects for the HPCI gland seal coolers, HPCI lube oil coolers, and HPCI and RCIC pump room coolers is acceptable.

HPCI also includes flex hoses made from neoprene or rubber. The applicant has identified loss of material properties as an applicable aging effect for HPCI flex hoses that are fabricated from neoprene or rubber and that are exposed to lubricating oil. Neoprene, an elastomer, is a form of rubber. Elastomers and rubber lose their elastic properties (thermally age or harden) over time. Radiation, ionic or organic impurities, and heat may accelerate the process. The staff therefore concurs that loss of material properties is an applicable effect for the HPCI ESF components made from neoprene and rubber and concludes that the applicant's identification of aging effects for the HPCI neoprene materials is acceptable.

<u>Aging Effects for the Surfaces of HPCI Components Exposed to Gas Environments</u>

In Table 3.2-1 of the LRA, the applicant lists the steam, wetted gas, ventilation air, and sheltered environments as the gas environments to which the HPCI components may be exposed. The applicant identified the following aging effects as applicable to the HPCI components that are exposed to steam or wetted gas environments and require aging management:

- loss of material in carbon steel exposed to steam and wetted gas

- loss of material and cracking of stainless steel exposed to steam

The applicant did not identify any aging effects as being applicable to the surfaces of HPCI components (including external surfaces of heat exchanger components in the HPCI pump room cooling coils, gland seal condensers, and turbine lube oil coolers) that are exposed to sheltered air or ventilation air environments.

The only HPCI and RCIC components that are exposed to steam conditions are fabricated from carbon or stainless steels. The applicant defines steam as a two-phase atmosphere containing water both in the liquid-phase (i.e., aqueous water) and in the gas phase (i.e., water vapor). The applicant stated that, at Peach Bottom, the quality of steam atmospheres ranges from high-quality steam (i.e., steam containing very little liquid-phase water) in the main steam system to low-quality steam (steam containing a considerable amount of liquid-phase water) in the HPCI and RCIC systems. Loss of material due to general corrosion may be an applicable effect for carbon steel HPCI and RCIC components that are exposed to low-quality steam conditions due to exposure of the carbon steel to the liquid-phase water in the steam. Stainless steel components are normally designed to resist general corrosion in this manner, although they may be susceptible to cracking induced by stress corrosion if halide or sulfate anions are present in the liquid-phase of the steam. Although the HPCI and RCIC steam lines normally see little to no steam flow because these systems operate infrequently, the applicant has identified loss of material as an applicable aging effect for the carbon steel HPCI and RCIC components that are exposed to steam conditions, and has conservatively identified both loss of material and cracking as applicable aging effects for the stainless steel HPCI components that are exposed to steam conditions. Based on these technical considerations, the staff concludes that the applicant has conservatively identified those aging effects that are applicable to the HPCI and RCIC components that are exposed to steam conditions. The staff therefore concludes the applicant’s identification of aging effects for the HPCI and RCIC components that are exposed to steam conditions is acceptable.

The applicant defines sheltered air as air or nitrogen containing some humidity. The applicant considers the ventilation air environment to be similar to the sheltered air environment, but has stated that the ventilation systems take their suction from either the building rooms or the outdoor environment, and that the internal temperature and humidity conditions for the ventilation atmosphere are controlled. Since moist air environments contain some liquid-phase water, loss of material induced by general corrosion may be an applicable effect for carbon steel HPCI and other ESF components that are exposed to moist air environments (which include wetted gas, ventilation air, and sheltered air), just as it may be an applicable aging effect for carbon steel components that are exposed to low-quality steam. The applicant has concluded that loss of material is not an applicable effect for ESF components exposed to these environments if humidity and temperatures are controlled or if the external surfaces are at the same temperature as or hotter than the ambient temperature for the sheltered air environment (so that the surfaces remain dry). In response RAI 3.2-1, the applicant clarified that antisweat insulation is installed on all ESF piping, valves, and fittings that are subject to humid air at operating temperatures of 30–60 °F or whose external surface temperatures are below the ambient temperature of the surrounding atmospheric environment. The applicant stated that this practice ensures that moisture is not in direct contact with exposed metal and therefore corrosion-induced aging effects (i.e., loss of material and cracking) are not relevant for metallic or rubber (including neoprene) components in sheltered air or ventilation air environments. The applicant's response to RAI 3.2-1 provides a sufficient basis for concluding that aging effects are not applicable for the surfaces of ESF components that are exposed to sheltered air or ventilation air environments. The staff therefore concludes that the applicant's identification of aging effects for HPCI and other ESF components under sheltered air or ventilation air conditions is acceptable.

The other gaseous environment applicable to the HPCI system is wetted gas. The applicant defines wetted gas environments as air, containment atmosphere, and diesel exhaust gas that may contain some moisture and/or corrosive impurities. Carbon steel components exposed to corrosive, liquid, or humid air environments may be susceptible to general corrosion. The applicant has therefore identified loss of material as an applicable aging effect for carbon or low-alloy steel HPCI and other ESF components that are exposed to wetted gas environments. In contrast, stainless steel components are designed to resist the effects of general corrosion. Loss of material is therefore not normally a concern for the surfaces of stainless steel RCIC components that are exposed to wetted gas. Stainless steel components, however, may be susceptible to stress corrosion cracking in steam or humid environments (including wetted gas). In RAI 3.2-2, the staff pointed out that the applicant did not always identify cracking as an applicable effect for stainless steel ESF components exposed to wetted gas conditions and asked the applicant to discuss its bases for excluding cracking as an applicable effect for these ESF components. In its response to RAI 3.2-2, the applicant stated that, for wetted gas environments, stress corrosion cracking was judged to be a concern for stainless steel only if there is a potential for concentration of contaminants, and that in the absence of a corrosive environment, stress corrosion cracking would not be an issue for the stainless steel ESF components exposed to wetted gas environments. In these cases, the applicant stated that its aging management reviews determined that the potential for concentration of contaminants was not significant. The applicant's response to RAI 3.2-2 provides a sufficient technical basis for concluding that cracking is not applicable for a number stainless steel HPCI and other ESF components that are identified in the ESF AMR tables (i.e., Tables 3.2-1 through 3.2-8 of the application) as being exposed to wetted gas environments, and specifically not applicable for those stainless steel HPCI and ESF components for which the applicant has omitted cracking as an applicable effect. Based on these considerations, the staff concludes that the applicant has either provided an acceptable technical basis for omitting an aging effect (i.e., cracking) as being applicable to the HPCI or other ESF components that are exposed to the wetted gas environment or conservatively identified those aging effects that are applicable to these components. The staff therefore finds that the applicant's identification of aging effects for HPCI and other ESF components that are exposed to the wetted gas environment is acceptable.

Based on these considerations, the staff finds the applicant's identification of aging effects for the HPCI and other ESF components that are exposed to steam, sheltered air, ventilation air, and wetted gas environments to be acceptable.

3.2.1.2.2 Aging Management Programs

The applicant identified the following AMPs and activities to manage the above aging effects for the HPCI components:

- The applicant has credited the demineralized water and condensate storage tank chemistry activities (LRA B.1.4) to manage loss of material, cracking, or reduction in heat transfer in stainless steel, carbon steel, and copper alloys in piping, valves, and heat exchangers. The staff evaluates these activities in Section 3.0.3.4 of this SER.

- The applicant has credited the reactor coolant system chemistry activities (LRA B.1.2) to manage loss of material and cracking in stainless steel, carbon steel, and copper alloys in piping, valves, and heat exchangers. The staff evaluates these activities in Section 3.0.3.2 of this SER.

- The applicant has credited the (ISI) program (LRA B.1.8) to manage loss of material and cracking in stainless steel, carbon steel, and copper in piping, valves, and heat exchangers. The staff evaluates these activities in Section 3.0.3.6 of this SER.

- The applicant has credited the torus water chemistry activities (LRA B.1.5) to manage loss of material and cracking in stainless steel and carbon steel in piping and valves. The staff evaluates these activities in Section 3.0.3.5 of this SER.

- The applicant has credited the torus piping inspection activities (LRA B.3.1) to manage loss of material in carbon steel in piping, pipe steam traps, and valves. The staff evaluates these activities in Section 3.0.3.21 of this SER.

- The applicant has credited the heat exchanger inspection activities (LRA B.2.12) to manage cracking, loss of material, and reduction in heat transfer in copper alloys and carbon steel in heat exchangers. The staff evaluates these activities in Section 3.0.3.17 of this SER.

- The applicant has credited the lubricating and fuel oil quality testing activities (LRA B.2.1) to manage loss of material, cracking, and heat transfer reduction in carbon steel, cast iron, copper alloys, stainless steel, brass alloys, and brass in valves, pump casings, heat exchangers, and lubricating oil tanks. The staff evaluates these activities in Section 3.0.3.18 of this SER.

- The applicant has credited the HPCI and RCIC turbine inspection activities (LRA B.2.10) to manage loss of material in carbon steel turbine casing and lubricating oil tanks, and loss of properties in neoprene and rubber in flex hoses. The staff evaluates these activities in the following paragraphs.

<u>HPCI and RCIC Turbine Inspection Activities</u>

The applicant described the HPCI and RCIC turbine inspection activities in Section B.2.10 of the LRA. This program provides aging management of the HPCI and RCIC turbine casings exposed to a wetted gas environment. The applicant stated that the HPCI turbine inspection activities additionally provide for condition monitoring of components exposed to a lubricating oil environment. The staff reviewed Section B.2.10 of the LRA to determine whether the HPCI and RCIC turbine inspection activities AMP will adequately manage the effects of aging during the period of extended operation as required by 10 CFR 54.21(a)(3).

The applicant described the HPCI and RCIC turbine inspection activities that provide for aging management of the HPCI and RCIC turbine casings exposed to a wetted gas environment and of the HPCI turbine components exposed to a lubricating oil environment. The inspection activities consist of visual inspections of the turbine casings and the HPCI lubricating oil tank internals for evidence of loss of material. The applicant further stated that a PBAPS procedure would be enhanced to inspect the HPCI lubricating oil system flexible hoses for changes in material properties. The HPCI and the RCIC turbine inspection activities are performed periodically during turbine maintenance in accordance with plant procedures.

The applicant concluded that based on PBAPS operating experience, there is reasonable assurance that the HPCI and RCIC turbine inspection activities will adequately manage the identified aging effects for the components so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

The staff's evaluation of the HPCI and RCIC turbine inspection activities focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicates that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below

Program Scope: The applicant described the program scope of the HPCI and RCIC turbine inspection activities as focusing on managing loss of material and change in material properties by the performance of periodic inspections of the turbine casings and HPCI lubricating oil system tank internals and flexible hoses. In LRA Table 3.2-1(aging management results for RCIC system), the HPCI and RCIC turbine inspection activities AMP is listed as the aging management program for lubricating oil tanks with lubricating oil as the applicable environment. Wetted gas environment is also in the program scope of the AMP. Therefore, the staff requested the applicant to identify the reference to the AMP being applied to components in a wetted gas environment. By letter dated April 29, 2002, the applicant responded that LRA Table 3.2-1 identifies a number of carbon steel and stainless steel components in a wetted gas environment. For carbon steel components in a wetted gas environment, the applicable aging management activity is referenced in the table. The aging management review has determined that the stainless steel components in the HPCI system (LRA Table 3.2-1) that are exposed to an internal environment of wetted gas do not have any aging effects that require aging management. The applicant stated that therefore no aging management activity is identified for these components in Table 3.2-1. The staff found the scope of the program to be acceptable because the LRA and the additional information provided to the staff the have adequately addressed the components whose aging effects can be managed by the application of the HPCI and RCIC turbine inspection activities. The staff notes that during a conference call on August 21, 2002, the applicant stated the flexible hoses were stainless steel rather than an elastomer of neoprene and rubber. In a call and electronic mail on September 6, 2002, the applicant stated that the stainless steel flexible hose was a gland seal bleed-off line subjected to a wetted gas internal environment and a sheltered air external environment (see LRA Table 3.2-1, page 3-24 third row titled “Elastomer Flex Hoses”) and do not require aging management. Therefore, the flexible hoses would not be covered by this program. The staff finds this acceptable because the stainless steel hoses subject to a wetted gas and sheltered environment do not require aging management. The applicant needs to confirm this information in writing. **This is part of Confirmatory Item 3.2.1.2.2-1.** The additional parts of this confirmatory item are discussed below in the parameters monitored or inspected, detection of aging effects, monitoring and trending, and acceptance criteria program elements.

Preventive Actions: The applicant stated that the HPCI and RCIC turbine inspection activities provide inspection methods to identify aging effects. The applicant concluded that there are no preventive or mitigating attributes associated with these activities. The staff found this program attribute acceptable because the staff considers inspection activities a means of detecting, not preventing, aging and, therefore, agrees that there are no preventive attributes associated with this AMP.

Parameters Monitored or Inspected: The applicant stated that the HPCI and RCIC turbine inspection activities consist of visual inspections of the turbine casings and the HPCI lubricating oil tank internals for evidence of loss of material. The applicant further stated that these activities would be enhanced to inspect the HPCI lubricating oil system flexible hoses for change in material properties. The staff requested additional information from the applicant on how the inspection of the lubricating oil tank internals is to be conducted and whether UT methodology also is used as part of the inspection procedures. By letter dated June 27, 2002, the applicant responded that the inside of the HPCI oil reservoir is cleaned with lint-free rags and inspected for signs of corrosion, scaling, or paint degradation. The applicant further stated that UT methodology is not a requirement in the inspection procedure. The staff noted that the applicant had committed to inspect the HPCI lubricating oil flexible hoses, but had not adequately described the visual inspections that will be performed to identify change in material properties of the flexible hoses in the HPCI lubricating oil system. Therefore, the staff could not conclude that the inspection activities for the HPCI lubricating oil flexible hoses provided adequate aging management. During a conference call on August 21, 2002, the applicant stated the flexible hoses were stainless steel rather than an elastomer of neoprene and rubber. In a call and electronic mail on September 6, 2002, the applicant stated that the stainless steel flexible hose was a gland seal bleed-off line subjected to a wetted gas internal environment and a sheltered air external environment (see LRA Table 3.2-1, page 3-24 third row titled “Elastomer Flex Hoses”) and do not require aging management. Therefore, while the applicant had previously committed to inspect the hoses, a commitment based on the assumption that the hoses were an elastomer of neoprene and rubber subjected to an oil environment, the applicant stated they no longer intended to inspect them since the environments are not expected to induce aging effects on the stainless steel hoses. The staff agrees that stainless steel hoses subject to wetted gas and sheltered environments do not require aging management. **This is part of Confirmatory Item 3.2.1.2.2-1.** Based on the information provided in the LRA, the additional information provided in response to the RAIs, and the information which is the subject of this confirmatory item, the staff found the description of the parameters monitored or inspected to be acceptable to mitigate aging degradation for components subject to the HPCI and RCIC turbine inspection activities.

Detection of Aging Effects: The applicant stated that visual inspections for evidence of loss of material are conducted in accordance with an existing PBAPS procedure. This procedure will be enhanced to include a visual inspection of HPCI lubricating oil system flexible hoses for change in material properties. The applicant further stated that the aging effects of loss loss of material and change in material properties are identified and corrected prior to a loss of intended function. The inspections are performed during the turbine maintenance.

The staff found this program attribute acceptable because the applicant's approach to detecting applicable aging effects is based on plant experience for the turbine casings and lubricating oil storage tank and is supplemented with activities to evaluate the flexible hoses. The program activities may be relied upon to provide reasonable assurance that aging effects will be detected before there is loss of intended function. However, as noted above, the applicant has stated that inspection of the flexible hoses is not required. **This is part of Confirmatory Item 3.2.1.2.2-1.**

Monitoring and Trending: The applicant stated that visual examinations are conducted on a periodic basis. The examinations monitor the turbine casings, HPCI lubricating oil storage tank, and HPCI lubricating oil system flexible hoses for evidence of aging degradation. The staff requested additional information from the applicant on the frequency of the examinations. By letter dated April 29, 2002, the applicant responded that the HPCI and RCIC turbine maintenance is performed every 8 years. This frequency is based on the plant-specific operating and maintenance experience with the HPCI and RCIC turbines. The component inspections are scheduled as part of the turbine maintenance. The staff finds the applicant's approach to monitoring and trending activities to be acceptable because it is based on methods that are sufficient to predict the extent of degradation so that timely corrective or mitigative actions are possible. However, as noted above, the applicant has stated that inspection of the flexible hoses is not required. **This is part of Confirmatory Item 3.2.1.2.2-1.**

Acceptance Criteria: The applicant stated that examinations for pitting of turbine casings are conducted in accordance with approved PBAPS procedures. Engineering evaluations of identified turbine casing pitting are performed and adequate corrective actions determined. The applicant stated that flexible hoses will be examined in accordance with approved PBAPS procedures and replaced when abnormal conditions are identified. The results of the examinations are documented. The applicant further stated that HPCI lubricating oil tank internals are inspected for corrosion and scaling. Engineering evaluations of identified loss of material are performed and adequate corrective actions determined. The staff finds this reasonable and acceptable. However, as noted above, the applicant has stated that inspection of the flexible hoses is not required. **This is part of Confirmatory Item 3.2.1.2.2-1.**

Operating Experience: The applicant stated that a review of the operating experience for PBAPS found that there have been no aging-related turbine casing failures resulting in a loss of intended function of the HPCI or RCIC turbines. The applicant further stated that minor HPCI lubricating oil system leakage events have been detected and corrected in a timely manner. The applicant concluded that there have been no HPCI lubricating oil age-related component failures resulting in a loss of intended function. The staff concludes that the aging management activities described above are based on plant experience. Therefore, the staff agrees that these activities are effective at maintaining the intended function of the systems, structures, and components that may be served by the HPCI and RCIC turbine inspection activities, and can reasonably be expected to do so for the period of extended operation.

The staff reviewed Section A.2.10 of the UFSAR Supplement (Appendix A of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of the systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activity as required by 10 CFR 54.21(d).

The staff concludes that, with the exception of Confirmatory Item 3.2.1.2.1-1, the applicant has demonstrated that the aging effects associated with the HPCI and RCIC inspection activities will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concluded that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

The applicant has credited the Generic Letter 89-13 activities (LRA B.2.8) to manage flow blockage in the copper cooling coils in the HPCI pump rooms. The staff evaluates these activities in Section 3.0.3.15 of this SER. The applicant has credited the flow-accelerated corrosion program (LRA B.1.1) to manage loss of material in carbon steel piping. The staff evaluates these activities in Section 3.0.3.1 of this SER.

The staff has evaluated these AMPs and found them to be acceptable for managing the aging effects identified for HPCI. On the basis of this review, the staff concludes that the applicant has provided adequate AMPs to manage the aging effects for these combinations of materials and environments and that the AMPs are consistent with published literature and industry experience.

3.2.1.3 Conclusions

The staff reviewed the information in LRA Section 3.2.1, "High-Pressure Coolant Injection System." On the basis of this review, the staff concludes that, with the exception of Confirmatory Item 3.2.1.2.1-1, the applicant has demonstrated that the aging effects associated with the HPCI system will be adequately managed so that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.2.2 Core Spray System

3.2.2.1 Technical Information in the Application

The applicant describes its AMRs of the Core Spray (CS) system components in Section 3.2.2 and Table 3.2-2 of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant demonstrated that the effects of aging associated with the CS system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3). A complete list of the CS components requiring AMRs and the component intended functions is provided in Table 3.2-2 of the application.

3.2.2.1.1 Aging Effects

In Table 3.2-2 of the application, the applicant identifies the following CS components that are subject to AMRs: pumps, valves, heat exchangers, piping, and piping specialities (restricting orifices, flow elements, thermowells, cyclone separators, and suction strainers).

In this table, the applicant identifies specific components fabricated from the following materials:

- stainless steel
- carbon steel
- cast iron
- galvanized carbon steel
- copper
- aluminum

The applicant identifies these components as subject to any of the following environments:

- condensate storage water
- reactor coolant
- torus-grade water
- raw water
- dry gas
- lubricating oil
- sheltered environment

The applicant describes the environmental conditions for these environments in Section 3.0 of the application.

The applicant identifies the following aging effects of applicable to the CS components:

- loss of material
- cracking
- heat transfer reduction capability
- flow blockages

3.2.2.1.2 Aging Management Programs

The applicant credits the following programs and activities for managing the aging effects attributed to these components:

- condensate storage tank chemistry activities
- reactor coolant system chemistry activities
- ISI Program
- torus water chemistry activities
- lubricating and fuel oil quality testing activities
- Generic Letter 89-13 activities
-

3.2.2.2 Staff Evaluation

The staff reviewed the component groups, intended functions, environments, materials of construction, aging effects, and aging management activities for the components of the CS system to determine whether the applicant has demonstrated that the effects of aging for this system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2.1 Effects of Aging

<u>Aging Effects for the Surfaces of CS Components Exposed to Liquid Environments</u>

CS has piping, pipe fittings and specialties, branch connections, pumps, valves, and heat exchanger components that are exposed to liquid environments, including the reactor coolant, condensate storage water, torus-grade water, and lubricating oil environments. The majority of these components are made from stainless steel or carbon steel (including galvanized steel), although some CS components are fabricated from copper/bronze/brass alloys, cast iron, or aluminum materials. The applicant identified the following aging effects as applicable to the CS components that are exposed to liquid environments:

- loss of material in carbon steel piping, pump, valve, and vessel components that are exposed to either reactor coolant or torus-grade water
- loss of material and cracking in stainless steel piping, pump, valve, and vessel components exposed to condensate storage water, reactor coolant, or torus-grade water
- cracking and heat transfer reduction in cast iron casings and stainless steel tubes in the CS pump motor oil coolers that are exposed to lubricating oil
- loss of material, cracking, loss of heat transfer function (reduction in heat transfer capability), and flow blockage in stainless steel and copper cooling coils exposed to raw water

The staff's evaluation of the applicant's identification of aging effects for stainless steel CS pressure boundary components that are exposed to condensate storage water, reactor coolant, torus-grade water, and lubricating oil environments is consistent with the staff's analysis in Section 3.2.1.2.1 for similar stainless steel HPCI components that are exposed to these environments. Based on this evaluation, the staff concludes that the applicant's evaluations of stainless steel CS components that are exposed to reactor coolant or torus-grade water environments are conservative, and are therefore acceptable.

The staff's evaluation of the applicant's identification of aging effects for carbon steel/low-alloy steel, cast iron, and copper CS components that are exposed to reactor coolant or torus-grade water is consistent with the staff's analysis in Section 3.2.1.2.1 for similar carbon steel/low-alloy steel, cast iron, and copper HPCI components that are exposed to these environments. Based on this evaluation, the staff concludes that the applicant's evaluations of carbon steel/low-alloy steel, cast iron, and copper CS components that are exposed to reactor coolant or torus-grade water environments are conservative, and are therefore acceptable.

The CS components within the scope of license renewal include the CS pump motor oil coolers and the CS pump room cooling coils. The CS pump motor oil coolers include stainless steel coils that are exposed to raw water internally and lubricating oil externally and cast iron frames that are exposed to lubricating oil internally and sheltered air externally. The staff's evaluation of the surfaces of the cast iron frames that are exposed to sheltered air is given in this section under the heading "Aging Effects for the Surfaces of CS Components Exposed to Gas Environments." Microbiological organisms and crud (sediment or oxidation products) may build up in heat exchanger components that are exposed to raw water sources. These aging mechanisms may result in loss of material by corrosion, stress cracking, or fouling of heat exchanger components that serve a pressure boundary function, reducing the amount of available heat transfer surface area in heat exchanger components that serve a heat transfer function. Highly stressed carbon steel and stainless steel heat exchanger components that are exposed to lubricating oil may be susceptible to stress-induced cracking or stress corrosion cracking. The applicant has conservatively identified loss of material, cracking, reduction in heat transfer capability, and flow blockage as applicable aging effects for the internal surfaces of the CS pump motor oil cooler coils that are exposed to raw water and cracking and heat transfer reduction as applicable aging effects for the surfaces of the CS pump motor oil cooler frames and coils that are exposed to lubricating oil. On the basis of these technical considerations, the staff concludes that the applicant has conservatively identified those aging effects that are applicable to the CS heat exchanger components that are exposed to liquid environments. The staff therefore finds that the applicant's identification of aging effects for these components is acceptable.

The designs of the CS pump room cooling coils are similar to the designs of the HPCI, RCIC, and RHR pump room cooling coils. The CS pump room cooling coils recirculate raw water through the cooling coil tubes to remove excess heat from the sheltered air conditions in the CS pump rooms. The components in these cooling coils therefore serve a heat transfer function in addition the pressure boundary function of the cooling coil tubes. The cooling coil tubesheets and frames are fabricated from galvanized carbon steel, the cooling coil fins are fabricated from aluminum, and the cooling coil tubes are fabricated from copper. The fins, frames, and tubesheets are exposed only to sheltered air conditions and the copper tubes are exposed to raw water internally and sheltered air externally. The applicant has identified cracking, loss of material, heat transfer reduction, and flow blockage as applicable aging effects for the surfaces of the CS pump room cooling coil tubes that are exposed to raw water. This is in agreement with the applicant's aging effect analysis for the CS pump motor oil cooler components that are exposed to raw water sources. On the basis of this consideration, the staff concludes that the applicant has conservatively identified those aging effects that are applicable to the CS pump room cooling coil components that are exposed to raw water. The staff therefore finds that the applicant's identification of aging effects for the pump room cooling coil components that are exposed to raw water is acceptable. The staff's evaluation of aging effects for the surfaces of the CS pump room cooling coil components that are exposed to sheltered air is given in this section under the heading "Aging Effects for the Surfaces of CS Components Exposed to Gas Environments."

<u>Aging Effects for the Surfaces of CS Components Exposed to Gas Environments</u>

The CS system has components that are exposed to the following gas environments: steam, wetted gas, and sheltered air. The applicant identified the following aging effects as applicable to the CS components that are exposed to steam or wetted gas environments and require aging management:

- loss of material in carbon steel exposed to steam and wetted gas
- loss of material and cracking of stainless steel exposed to steam
- heat transfer reduction for aluminum fins, copper tubes and galvanized carbon steel tubesheets and frames in the in the CS pump room cooling coils that are exposed to the sheltered air environment

The applicant did not identify any aging effects for carbon steel, cast iron, copper, or stainless steel CS components that are exposed dry gas or sheltered environments and that serve a pressure boundary function. Dry gas environments are not humid or corrosive enough for aging effects to be of concern for metallic plant components. Based on this consideration, the staff concludes that applicant has provided an acceptable basis for omitting aging effects for the carbon steel, cast iron, copper, and stainless steel CS components that are exposed to dry gas. The staff's evaluation of the aging effects that are applicable to carbon steel, cast iron, copper, and stainless steel CS components that are exposed sheltered air is given in the following paragraph.

The staff's evaluation of the applicant's identification of aging effects for carbon steel, cast iron, copper, and stainless steel CS components that are exposed to steam, sheltered air, or wetted gas environments is consistent with the staff's analysis in Section 3.2.1.2.1 for similar HPCI components that are exposed to these environments. The applicant has also identified reduction in heat transfer capability as an applicable effect for the surfaces of the CS pump room cooling coil aluminum fins, copper tubes, and galvanized carbon steel tubesheets and frames that are exposed to the sheltered air environment and serve a heat transfer function because of the components susceptibility to general corrosion. This is conservative. On the basis of these technical considerations, the staff concludes that the applicant has either provided an acceptable technical basis for omitting loss of material and/or cracking as an applicable effect for a given CS component that is exposed to a steam, sheltered air, dry air, or wetted gas environment or has conservatively identified those aging effects that are applicable to the CS components that are exposed to these gas environments. The staff therefore concludes that the applicant's identification of aging effects for the CS components that are exposed tor steam, sheltered air, dry air, and wetted gas environments is acceptable.

3.2.2.2.2 Aging Management Programs

The applicant identified the following AMPs and activities to manage the above aging effects for the CS components:

- The applicant has credited the demineralized water and condensate storage tank chemistry activities (LRA B.1.4) to manage loss of material, cracking, or reduction in heat transfer in stainless steel, carbon steel, and copper alloys in piping, valves and heat exchangers. The staff evaluates these activities in Section 3.0.3.4 of this SER.
- The applicant has credited the reactor coolant system chemistry activities (LRA B.1.2) to manage loss of material and cracking in stainless steel, carbon steel, and copper alloys

in piping, valves, and heat exchangers. The staff evaluates these activities in Section 3.0.3.2 of this SER.

- The applicant has credited the (ISI) program (LRA B.1.8) to manage loss of material and cracking in stainless steel, carbon steel, and copper in piping, valves and heat exchangers. The staff evaluates these activities in Section 3.0.3.6 of this SER.
- The applicant has credited the torus water chemistry activities (LRA B.1.5) to manage loss of material and cracking in stainless steel and carbon steel in piping and valves. The staff evaluates these activities in Section 3.0.3.5 of this SER.

- The applicant has credited the lubricating and fuel oil quality testing activities (LRA B.2.1) to manage loss of material, cracking, and heat transfer reduction in carbon steel, cast iron, copper alloys, stainless steel, brass alloys, or brass in valves, pump casings, heat exchangers, and lubricating oil tanks. The staff evaluates these activities in Section 3.0.3.18 of this SER.

- The applicant has credited the Generic Letter 89-13 activities (LRA B.2.8) to manage flow blockage in the copper cooling coils in the HPCI pump rooms. The staff evaluates these activities in Section 3.0.3.15 of this SER.

The staff has evaluated these AMPs and found them to be acceptable for managing the aging effects identified for the CS system. On the basis of this review, the staff concludes that the applicant has provided adequate AMPs to manage the aging effects for these combinations of materials and environments and that these AMPs are consistent with published literature and industry experience.

3.2.2.2.3 Conclusions

The staff has reviewed the information in Section 3.2.1, "Core Spray System," of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the CS system will be adequately managed so that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the CS system discussed above as required by 10 CFR 54.21(d).

3.2.3 Primary Containment Isolation System

3.2.3.1 Technical Information in the Application

The applicant described its AMR of the primary containment isolation system (PCIS) for license renewal in Section 3.2.3 and Table 3.2-3 of the LRA. The staff reviewed this section to determine whether the applicant demonstrated that the effects of aging on the primary containment isolation system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3). A complete list of the PCIS components requiring AMRs and the component intended functions is provided in Table 3.2-3 of the application.

3.2.3.1.1 Aging Effects

In Table 3.2-3 of the application, the applicant identifies that the following PCIS components as subject to AMRs: valve bodies, piping, tubing, and piping specialties (i.e., restricting orifices and flow elements). In this table, the applicant also identifies these components as fabricated from either carbon steel or stainless steel (including cast austenitic stainless steel).

The applicant identifies these components as subject to any of the following environments:

- closed cooling water
- reactor coolant
- dry gas
- wetted gas
- sheltered air environment

The applicant describes the environmental conditions for these environments in Section 3.0 of the application.

The applicant identifies the following aging effects as applicable to the PCIS components:

- loss of material
- cracking
- loss of fracture toughness

3.2.3.1.2 Aging Management Programs

The applicant credits the following programs and activities for managing the aging effects associated with these components:

- closed cooling water chemistry activities
- ISI Program
- reactor coolant system chemistry activities
- primary containment leakage rate testing program

Table 3.2-3 of the application identifies which of these specific programs will be used to manage the aging effects for the specific component material/environmental-condition combinations identified in the table.

3.2.3.2 Staff Evaluation

The staff reviewed the component groups, intended functions, environments, materials of construction, aging effects, and aging management activities for the PCIS components identified in Table 3.2-3 of the LRA to determine whether the applicant has demonstrated that the effects of aging will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.3.2.1 Aging Effects

Aging Effects for the Surfaces of PCIS Components Exposed to Liquid Environments

PCIS includes the following components that are subject to AMRs: valve bodies, piping, tubing, and piping specialties (i.e., restricting orifices and flow elements). These components are fabricated from either carbon steel or stainless steel materials (including cast austenitic stainless steel) and may be exposed to reactor coolant and closed cooling water environments. The applicant identified the following aging effects as applicable to the PCIS components that are exposed to these liquid environments:

- loss of material in carbon steel components that are exposed to reactor coolant and closed cooling water environments

- loss of material and cracking in stainless steel components (including cast austenitic stainless steel [CASS]) that are exposed to the reactor coolant environment

- loss of fracture toughness of cast austenitic stainless steel components that are exposed to the reactor coolant

The staff's evaluation of the applicant's identification of aging effects for stainless steel PCIS pressure boundary components that are exposed to the reactor coolant environment is consistent with the staff's analysis in Section 3.2.1.2.1 for similar stainless steel HPCI components that are exposed to these environments. PCIS includes some CASS valve bodies that are exposed to reactor coolant. The applicant has identified loss of fracture toughness as an additional aging effect for the CASS valve bodies. Based on this evaluation, the staff concludes that the applicant's evaluation of stainless steel PCIS components that are exposed to the reactor coolant environment is conservative and is therefore acceptable.

The staff's evaluation of the applicant's identification of aging effects for carbon steel PCIS components that are exposed to the reactor coolant or closed cooling water environments is consistent with the staff's analysis in Section 3.2.1.2.1 for similar carbon steel HPCI components that are exposed to these environments. Based on this evaluation, the staff concludes that the applicant's evaluations of carbon steel PCIS components that are exposed to reactor coolant or closed cooling water environments are conservative and are therefore acceptable.

Aging Effects for the Surfaces of PCIS Components Exposed to Gas Environments

PCIS includes components that may be exposed to the following gas environments: dry gas, sheltered air, and wetted gas. The applicant identified the following aging effect as applicable to the PCIS components that are exposed to gas environments:

- loss of material in carbon steel components that are exposed to a wetted gas environment.

The applicant did not identify any aging effects for the carbon steel and stainless steel PCIS components (including cast austenitic stainless steel components) that are exposed to dry gas or sheltered environments and that serve a pressure boundary function. Dry gas environments are not humid or corrosive enough for aging effects to be of a concern for metallic plant components. The staff's evaluation of the applicant's identification of aging effects for carbon steel, cast iron, copper, or stainless steel PCIS components that are exposed to steam, sheltered air, or wetted gas environments is consistent with the staff's analysis in Section 3.2.1.2.1 for similar HPCI components that are exposed to these environments. On the basis of this evaluation, the staff concludes that the applicant's evaluations of PCIS components in sheltered air, dry air, and wetted gas environments either provides an acceptable technical basis for omitting an aging effect as not applicable to a given PCIS component or conservatively identifies the aging effects that are applicable to the PCIS that are exposed to sheltered air, dry air, or wetted gas environments. The staff therefore finds that the applicant's identification of aging effects for the PCIS components that are exposed to gas environments is acceptable.

3.2.3.2.2 Aging Management Programs

The applicant identified that the following AMPs and activities for managing the aging effects that are applicable to the PCIS components:

- The applicant has credited the closed cooling water chemistry activities (LRA B.1.3) to manage loss of material in carbon steel in piping and valve bodies. The staff evaluates these activities in Section 3.0.3.3 of this SER.

- The applicant has credited the reactor coolant system chemistry program (LRA B.1.2) to manage cracking and loss of material in stainless steel and carbon steel in piping, restricting orifices, flow elements, and valve bodies. The staff evaluates these activities in Section 3.0.3.2 of this SER.

- The applicant has credited the primary containment leakage rate testing program (LRA B.1.10) to manage loss of material in carbon steel piping and valve bodies. The staff evaluates these activities in Section 3.0.3.8 of this SER.

- The applicant has credited the (ISI) program (LRA B.1.8) to manage cracking and loss of material in stainless steel, cast austenitic stainless steel, and carbon steel piping and valve bodies. The staff evaluates these activities in Section 3.0.3.6 of this SER.

The staff has evaluated these AMPs and found them to be acceptable for managing the aging effects identified for the PCIS system. On the basis of this review, the staff concludes that the applicant has provided adequate AMPs to manage the aging effects for these combinations of materials and environments and that these AMPs are consistent with published literature and industry experience.

3.2.3.3 Conclusions

The staff reviewed the information in LRA Section 3.2.3, "Primary Containment Isolation System." On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the primary containment isolation system will be adequately managed so that there is reasonable assurance that this system will perform its intended function in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.4 Reactor Core Isolation Cooling System

3.2.4.1 Technical Information in the Application

The applicant described its AMR for the reactor core isolation cooling (RCIC) systems in Section 3.2, “Aging Management of Engineered Safety Features,” and Table 3.2-4, “Reactor Core Isolation Cooling System,” of the application. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging for RCIC will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3). A complete list of the RCIC components requiring AMRs and the component intended functions is provided in Table 3.2-4 of the application.

3.2.4.1.1 Aging Effects

In Table 3.2-4 of the application, the applicant identifies the following RCIC components that are subject to AMRs: valve bodies, pump casings, strainer bodies, turbine casings, heat exchangers and their subcomponents (including channel heads, tubesheets, shells, coils and tubes), piping, piping specialties, and tanks. The RCIC components in this table, are fabricated either from stainless steel, carbon/low-alloy steel, copper alloys (i.e., copper, brass, or bronze), or aluminum materials.

The applicant identifies that the RCIC components are subject to any of the following environments:

- condensate storage water
- torus-grade water
- torus-grade water with a gas interface
- raw water
- reactor coolant
- lubricating oil
- steam
- wetted gas
- sheltered air

The applicant describes the environmental conditions for these environments in Section 3.0 of the application.

The applicant identifies the following aging effects as applicable to the RCIC components:

- loss of material
- cracking
- heat transfer reduction capability
- flow blockages

3.2.4.1.2 Aging Management Programs

The applicant credits the following programs and activities for managing the aging effects attributed to the RCIC components:

- CST Chemistry Program
- Lubricating and Fuel Oil Quality Testing Activities
- RCS Chemistry Program
- ISI Program
- Torus Water Chemistry Program
- HPCI and RCIC Turbine Inspection Activities
- Torus Piping Inspection Activities
- Heat Exchanger Inspection Activities
- GL 89-13 Activities
- Flow-Assisted Corrosion (FAC) Program

Table 3.2-4 of the application identifies which of these programs will be used to manage the aging effects for the specific RCIC component material/environmental-condition combinations identified in the table.

3.2.4.2 Staff Evaluation

The staff reviewed the component groups, intended functions, environments, materials of construction, aging effects, and aging management activities for the RCIC system in Table 3.2-4 of the LRA to determine whether the applicant has demonstrated that the effects of aging system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.4.2.1 Effects of Aging

<u>Aging Effects for the Surfaces of RCIC Components Exposed to Liquid Environments</u>

In Table 3.2-3 of the LRA, the applicant identified the following liquid environments to which the RCIC components may be exposed: reactor coolant, condensate storage water, torus-grade water (including torus-grade water with gas interface), raw water, and lubricating oil. The applicant defines these environments in Section 3.0 of the application. The applicant identified the following aging effects as applicable to the RCIC components that are exposed to these liquid environments and requiring aging management:

- loss of material and cracking for stainless steel RCIC components in condensate storage water and torus-grade water environments

- loss of material for carbon steel RCIC components exposed to condensate storage water, torus-grade water, reactor coolant, and lubricating oil environments

- cracking and reduction in heat transfer capability as additional aging effects that require management for the carbon steel RCIC turbine lube oil cooler shells and tubesheets that are exposed to a condensate storage water environment

- loss of material, cracking, and reduction in heat transfer capability for admiralty brass tubes in the RCIC turbine lube oil coolers exposed to condensate storage water or lubricating oil environments

- loss of material for bronze/brass valve bodies or pipe fittings exposed to a lubricating oil environment

- loss of material, cracking, and flow blockage for copper RCIC pump room cooling coils (i.e., copper tubing) exposed to a raw water environment

The staff's evaluation of the applicant's identification of aging effects for stainless steel RCIC pressure boundary components that are exposed to condensate storage water or torus-grade water environments is consistent with the staff's analysis in Section 3.2.1.2.1 for similar stainless steel HPCI components that are exposed to these environments. Based on the staff's evaluation in Section 3.2.1.2.1 of this SER, the staff concludes that the applicant's identification of aging effects for the stainless steel RCIC pressure boundary components that are exposed to condensate storage water or torus-grade water environments is conservative and is therefore acceptable.

The staff's evaluation of the applicant's identification of aging effects for carbon steel, copper, or admiralty brass RCIC components that are exposed to condensate storage water, reactor coolant, torus-grade water, raw water, or lubricating oil environments is consistent with the staff's analysis in Section 3.2.1.2.1 for similar carbon steel HPCI components that are exposed to liquid environments. Based on the staff's evaluation in Section 3.2.1.2.1 of this SER, the staff concludes that the applicant's identification of aging effects for the carbon steel RCIC piping, pump, turbine, and valve components that are exposed to liquid environments and which serve a pressure boundary function is conservative and is therefore acceptable.

RCIC includes two types of heat exchangers, the RCIC turbine lube oil coolers and the RCIC pump room cooling coils. The staff's evaluation of the applicant's identification of aging effects for the RCIC turbine lube oil coolers and the RCIC pump room cooling coils is consistent with the staff's analysis in Section 3.2.1.2.1 for similar components in the HPCI turbine lube oil coolers and the HPCI pump room cooling coils. Based on the staff's evaluation in Section 3.2.1.2.1 of this SER, the staff concludes that the applicant, in its evaluation of the RCIC turbine lube oil coolers and the RCIC pump room cooling coils, has either provided an acceptable technical basis for omitting an aging effect as not applicable to the RCIC turbine lube oil coolers or the RCIC pump room cooling coils (i.e., an acceptable basis for omitting reduction in heat transfer as an applicable effect for the pump room cooling coils) or has conservatively identified those aging effects that are applicable to the RCIC tubine lube oil coolers and RCIC pump room cooling coils. Based on these considerations, the staff finds acceptable the applicant's identification of aging effects for the RCIC tubine lube oil cooler components and RCIC pump room cooling coil components in liquid environments acceptable.

<u>Aging Effects for the Surfaces of RCIC Components Exposed to Gas Environments</u>

RCIC includes components that may be exposed to steam, sheltered air, and wetted gas environments. The applicant identified the following aging effects as applicable to the RCIC components that are exposed to these gas environments and requiring aging management:

- loss of material in carbon steel or low-alloy steel RCIC components that are exposed to steam or wetted gas

- loss of material and cracking of stainless steel RCIC components that are exposed to steam

The staff's evaluation of the applicant's identification of aging effects for the RCIC components that are exposed to steam, wetted gas and sheltered air environments is consistent with the staff's analysis in Section 3.2.1.2.1 for similar HPCI components that are exposed to these environments. Based on the staff's evaluation in Section 3.2.1.2.1 of this SER, the staff concludes that the applicant's identification of aging effects for the RCIC components that are exposed to gaseous environments is conservative and is therefore acceptable.

3.2.4.2.2 Aging Management Programs

The applicant identified the following AMPs and activities to manage the above aging effects for the RCIC components:

- The applicant has credited the demineralized water and condensate storage tank chemistry activities (LRA B.1.4) to manage loss of material, cracking, or reduction in heat transfer in stainless steel, carbon steel, and copper alloys in piping, valves, and heat exchangers. The staff evaluates these activities in Section 3.0.3.4 of this SER.

- The applicant has credited the reactor coolant system chemistry activities (LRA B.1.2) to manage loss of material and cracking in stainless steel, carbon steel, and copper alloys in piping, valves, and heat exchangers. The staff evaluates these activities in Section 3.0.3.2 of this SER.

- The applicant has credited the (ISI) program (LRA B.1.8) to manage loss of material and cracking in stainless steel, carbon steel, and copper in piping, valves, and heat exchangers. The staff evaluates these activities in Section 3.0.3.6 of this SER.

- The applicant has credited the torus water chemistry activities (LRA B.1.5) to manage loss of material and cracking in stainless steel and carbon steel in piping and valves. The staff evaluates these activities in Section 3.0.3.5 of this SER.

- The applicant has credited the torus piping inspection activities (LRA B.3.1) to manage loss of material in carbon steel in piping, pipe steam traps, and valves. The staff evaluates these activities in Section 3.0.3.21 of this SER.

- The applicant has credited the heat exchanger inspection activities (LRA B.2.12) to manage cracking, loss of material, and reduction in heat transfer in copper alloys and carbon steel in heat exchangers. The staff evaluates these activities in Section 3.0.3.17 of this SER.

- The applicant has credited the HPCI and RCIC turbine inspection activities (LRA B.2.10) to manage loss of material in carbon steel turbine casing and lubricating oil tanks and change in properties of neoprene and rubber in flex hoses. The staff evaluates these activities in Section 3.2.1.2.2.1 of this SER.

- The applicant has credited the lubricating and fuel oil quality testing activities (LRA B.2.1) to manage loss of material, cracking, and heat transfer reduction in carbon steel, cast iron, copper alloys, stainless steel, brass alloys, or brass in valves, pump casings, heat exchangers, and lubricating oil tanks. The staff evaluates these activities in Section 3.0.3.18 of this SER.

- The applicant has credited the Generic Letter 89-13 activities (LRA B.2.8) to manage flow blockage in the copper cooling coils in the HPCI pump rooms. The staff evaluates these activities in Section 3.0.3.15 of this SER.

- The applicant has credited the flow-accelerated corrosion program (LRA B.1.1) to manage loss of material in carbon steel piping. The staff evaluates these activities in Section 3.0.3.1 of this SER.

The staff has evaluated these AMPs and found them to be acceptable for managing the aging effects identified for the high-pressure coolant injection system. On the basis of this review, the staff concludes that the applicant has provided adequate AMPs to manage the aging effects for these combinations of materials and environments that are consistent with published literature and industry experience.

3.2.4.3 Conclusions

The staff reviewed the information in LRA Section 3.2.4, “Reactor Core Isolation Cooling System.” On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the RCIC system will be adequately managed so that there is reasonable assurance that this system will perform its intended function in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.5 Residual Heat Removal

3.2.5.1 Technical Information in the Application

The applicant described its AMR for the residual heat removal (RHR) system in Section 3.2, “Aging Management of Engineered Safety Features,” and Table 3.2-5, “Residual Heat Removal System,” of the application. The staff reviewed these sections of the applications to determine whether the applicant has demonstrated that the effects of aging on the RHR system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3). A complete list of the RHR components requiring AMRs and the component intended functions is provided in Table 3.2-5 of the application.

3.2.5.1.1 Aging Effects

In Table 3.2-5 of the application, the applicant identifies the major flowpaths of RHR as including piping, piping specialties (i.e., thermowells, cyclone separators, restricting orifices, flow elements, and suction strainers), valve bodies, pump casings, and heat exchangers and their subcomponents (i.e., coils, tubes, tubesheets, channels, baffles, nozzles, fins, shells, and internals) that are fabricated from stainless steel (including galvanized stainless steel), carbon/low-alloy steel materials, copper alloys (copper, bronze, or brass), or aluminum.

The applicant identifies that the RHR components are subject to any of the following environments:

- torus-grade water
- torus-grade water with a gas interface
- raw water
- reactor coolant
- dry gas
- sheltered air
- wetted gas

The applicant describes the environmental conditions for these environments in Section 3.0 of the application.

The applicant identifies the following aging effects as applicable to the RHR components:

- loss of material
- cracking
- heat transfer reduction
- flow blockage

3.2.5.1.2 Aging Management Programs

The applicant credits the following programs and activities for managing the aging effects attributed to the RHR components:

- RCS Chemistry Program
- ISI Program
- Torus Water Chemistry Program
- Primary Containment Leakage Rate Testing Program
- High-Pressure Service Water (HPSW) Radioactive Monitoring Activities
- Torus Piping Inspection Activities
- IST Program
- GL 89-13 Activities

3.2.5.2 Staff Evaluation

The staff reviewed the component groups, intended functions, environments, materials of construction, aging effects, and aging management activities for the RHR system in Table 3.2-5 of the LRA to determine whether the applicant has demonstrated that the effects of aging will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.5.2.1 Aging Effects

<u>Aging Effects for the Surfaces of RHR Components Exposed to Liquid Environments</u>

RHR includes piping, piping specialties (i.e., thermowells, cyclone separators, restricting orifices, flow elements, and suction strainers), valve bodies, pump casings, and heat exchangers and their subcomponents (i.e., coils, tubes, tubesheets, channels, baffles, nozzles, fins, shells, and/or internals). These components are fabricated from stainless steel (including galvanized stainless steel), carbon/low-alloy steel, copper alloys (copper, bronze, or brass), or aluminum and are exposed to either condensate storage water, reactor coolant, torus-grade water, or lubricating oil environments. The applicant identified the following aging effects as applicable to the RHR components that are exposed to these environments:

- loss of material and cracking for stainless steel RHR pump, valve, and piping components in reactor coolant and torus-grade water

- loss of material for carbon steel RHR pump, valve, and piping components exposed to reactor coolant and torus-grade water

- loss of material, cracking, flow blockage, and reduction in heat transfer capability for surfaces of copper and stainless steel RHR heat exchanger tubes exposed to raw water

- loss of material, cracking, and reduction in heat transfer capability for surfaces of stainless steel and carbon steel RHR heat exchanger components exposed to torus-grade water

The staff's evaluation of the applicant's identification of aging effects for stainless steel RHR pressure boundary components that are exposed to reactor coolant, torus-grade water, or raw water environments is consistent with the staff's analysis in Section 3.2.1.2.1 for similar stainless steel HPCI components that are exposed to these environments. Based on the staff's evaluation in Section 3.2.1.2.1 of this SER, the staff concludes that the applicant's identification of aging effects for the stainless steel RHR components that are exposed to reactor coolant or torus-grade water environments is conservative and is therefore acceptable.

The staff's evaluation of the applicant's identification of aging effects for carbon steel/low-alloy steel RHR pump, valve, and piping components that are exposed to the reactor coolant or torus-grade water is consistent with the staff's analysis in Section 3.2.1.2.1 for similar carbon steel/low HPCI piping, pump, and valve components that are exposed to these environments. Based on the staff's evaluation of valve components in liquid environments in Section 3.2.1.2.1 of this SER, the staff concludes that the applicant's identification of aging effects for the carbon steel/low-alloy steel RHR piping, pump, and valve components that are exposed to reactor coolant or torus-grade water environments is conservative and is therefore acceptable.

The RHR components within the scope of license renewal also include the RHR heat exchangers and the RHR pump room cooling coils. These heat exchangers serve safety-related heat transfer functions in addition to pressure boundary functions. The RHR heat exchangers include stainless steel tubes and tubesheets and carbon steel channels that are exposed to raw water internally and torus-grade water externally, as well as carbon steel shells, baffles, and nozzles that are exposed to torus-grade water internally and sheltered air externally. Heat exchanger components that are highly stressed may be subject to a number of mechanisms, including loss of material by pitting or erosion and stress-induced cracking, which in turn may reduce the heat transfer capability of the heat exchanger components. Heat exchanger tubes and tubesheets that are exposed to raw water sources may also be exposed to biological organisms or crud (i.e., sediment or oxidation products), which, if not attended to, may restrict coolant flow through the tubes and inhibit the heat transfer capability of the heat exchangers. The applicant has adequately identified loss of material, cracking, heat transfer reduction function, and flow blockage as applicable effects for the surfaces of the RHR heat exchanger tubes, tubesheets, and channels that are exposed to raw water and loss of material, cracking, and heat transfer reduction function as applicable effects for the surfaces of the carbon steel shells, baffles, and nozzles that are exposed to torus-grade water. The staff therefore concludes that the applicant's identification of aging effects for the RHR heat exchanger components that are exposed to liquid environments is conservative and is therefore acceptable.

The materials of fabrication, design, and environmental conditions of the RHR pump room cooling coils are similar to those for the CS pump room cooling coils. The staff's evaluation of the applicant's identification of aging effects for the RHR pump room cooling coil components is consistent with the staff's analysis in Section 3.2.2.2.1 for similar CS pump room cooling coil components under liquid conditions. Based on the staff's evaluation in Section 3.2.2.2.1 of this SER, the staff concludes that the applicant's identification of aging effects for the RHR pump room cooling coils in liquid environments is conservative and is therefore acceptable.

The staff's evaluation of the applicant's identification of aging effects for the surfaces of the RHR heat exchangers and RHR pump room cooling coils under sheltered air conditions is given below under the heading Aging Effects for the Surfaces of RHR Components Exposed to Gas Environments.

<u>Aging Effects for the Surfaces of RHR Components Exposed to Gas Environments</u>

The RHR components are exposed to either dry gas, sheltered air, or wetted gas environments. In Table 3.2-5, the applicant identified the following aging effects as applicable to the RHR components that are exposed to these gas environments:

- loss of material in carbon steel RHR components exposed to wetted gas environments

- reduction in heat transfer capability for surfaces of carbon steel (including galvanized steel), aluminum, and copper RHR heat exchanger type components (i.e., RHR heat exchanger and RHR pump room cooler components) that are exposed to sheltered air and that serve a heat transfer function.

The staff's evaluations of the applicant's identification of aging effects for the surfaces of the stainless steel and carbon steel/low-alloy steel RHR pump, valve, and piping components that are exposed to the dry gas, sheltered air, or wetted gas environments and the carbon steel RHR heat exchanger casings that are exposed to sheltered air are consistent with the staff's evaluations in Section 3.2.1.2.1 for similar stainless steel and carbon steel/low-alloy steel HPCI components that are exposed to these environments. Based on the staff's evaluation in Section 3.2.1.2.1 of this SER, the staff concludes that the applicant's identification of aging effects for the surfaces of the stainless steel and carbon steel/low-alloy steel RHR pump, valve, and piping components that are exposed to the dry gas, sheltered air, or wetted gas environments and the carbon steel RHR heat exchanger casings that are exposed to sheltered air either provides an acceptable technical basis for omitting an aging effect as not applicable to a given RHR component (i.e., for concluding that loss of material and/or cracking is not applicable to a given RHR pump, valve, or piping component in a dry gas, sheltered air, or wetted gas environment) or has conservatively identified those aging effects that are applicable to the RHR pump, valve, and piping components in dry gas, sheltered air, or wetted gas environments. Based on these considerations that staff finds acceptable the applicant's identification of aging effects for the RHR pump, valve, and piping components and the RHR heat exchanger casing that are exposed to gaseous environments.

The staff's evaluations of the applicant's identification of aging effects for the RHR pump room cooling coil frames, tubesheets, tubes, and fins that are exposed to sheltered air is consistent with the staff's evaluation in Section 3.2.2.2.1 of this SER for similar CS pump room cooler components under this environment. Based on the staff's evaluation in Section 3.2.2.2.1 of this SER, the staff concludes that the applicant's identification of aging effects for the RHR pump, room cooling coil components that are exposed to shelter air is conservative and is therefore acceptable.

3.2.5.2.2 Aging Management Programs

The applicant will use the following programs and activities for managing the aging effects that are applicable to the RHR components:

- The applicant has credited the reactor coolant system chemistry activities (LRA B.1.2) to manage loss of material and cracking in stainless steel, carbon steel, and copper alloys in piping, valves, and heat exchangers. The staff evaluates these activities in Section 3.0.3.2 of this SER.

- The applicant has credited the (ISI) program (LRA B.1.8) to manage loss of material and cracking in stainless steel, carbon steel, and copper in piping, valves, and heat exchangers. The staff evaluates these activities in Section 3.0.3.6 of this SER.
- The applicant has credited the torus water chemistry activities (LRA B.1.5) to manage loss of material and cracking in stainless steel and carbon steel in piping and valves. The staff evaluates these activities in Section 3.0.3.5 of this SER.

- The applicant has credited the torus piping inspection activities (LRA B.3.1) to manage loss of material in carbon steel in piping, pipe steam traps, and valves. The staff evaluates these activities in Section 3.0.3.21 of this SER.

- The applicant has credited the primary containment leakage rate testing program (LRA B.1.10) to manage loss of material in carbon steel piping and valve bodies. The staff evaluates these activities in Section 3.0.3.8 of this SER.

- The applicant has credited the inservice testing (IST) program (LRA B.1.11) to provide for inservice testing of Class 1, 2, and 3 pumps and valves in compliance with the ASME O&M Code, 1990 Edition, and 10 CFR 50.55a, to manage flow blockage in the emergency service water (ESW) and emergency cooling water (ECW) components, and to manage heat transfer reduction for the torus water that flows through the RHR heat exchangers. The staff evaluates this program in Section 3.0.3.10 of this SER.

- The applicant has credited the Generic Letter 89-13 activities (LRA B.2.8) to manage flow blockage in the copper cooling coils in the HPCI pump rooms. The staff evaluates these activities in Section 3.0.3.15 of this SER.

High Pressure Service Water Radioactivity Monitoring Activities

The applicant has credited the high-pressure service water (HPSW) radioactive monitoring activities (LRA B.1.7) to manage loss of material and cracking in the RHR heat exchangers The staff evaluates this activity as follows:

The applicant described the high pressure service water (HPSW) radioactivity monitoring activities AMP in Section B1.7 of Appendix B of the LRA. The staff reviewed the applicant's description of the AMP in the LRA to determine whether the applicant has demonstrated that the HPSW radioactivity monitoring activities AMP will adequately manage the applicable effects of aging of the RHR heat exchanger tubes and tube sheets exposed to raw water during the period of extended operation, as required by 10 CFR 54.21(a)(3).

In Section B1.7 of the LRA, the applicant identified the HPSW radioactivity monitoring activities as an existing aging management program that will be used by the applicant to manage loss of material and cracking in the tubes and tube sheets of the RHR heat exchangers together with the Generic Letter 89-13 activities AMP. The tubes and tube sheets are exposed to raw water. The HPSW radioactivity monitoring activities AMP consists of weekly sampling and analysis of the HPSW system water (raw water) to confirm the absence of radioactive contaminants. The Generic Letter 89-13 activities AMP also manages flow blockage and reduction of heat transfer in the RHR heat exchangers, including tubes and tube sheets. The staff's evaluation of the GL 89-13 activities AMP is provided in Section 3.0.3.15 of this SER.

The staff's evaluation of the high pressure service water radioactivity monitoring activities focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicates that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

Program Scope: The HPSW radioactivity monitoring activities AMP consists of routine sampling and analysis of the HPSW system water (i.e., raw water) contained in the RHR heat exchangers to verify the absence of radioactive contaminants. The staff found the scope of the program to be acceptable because the applicant adequately addressed the component whose aging effect(s) could be managed by the application of this activity.

Preventive or Mitigative Action: The applicant indicated that this AMP is a monitoring AMP. The applicant did not provide any preventive or mitigative actions for this activity, nor did the staff identify a need for such. The monitoring activities are a means of detecting, not preventing aging and, therefore, the staff agrees that no preventive actions are applicable to the HPSW radioactivity monitoring activities.

Parameters Monitored or Inspected: The HPSW radioactivity monitoring activities AMP monitors the radioactive isotopes that do not occur naturally. Samples taken from selected system test points and the bottom head drains of the heat exchangers are analyzed. The staff found the parameters monitored acceptable because loss of material and cracking can be identified by the presence of radioactive contaminants contained in raw water of the RHR heat exchangers.

Detection of Aging Effects: Sampling and analysis are performed weekly to confirm the absence of radioactive contaminants. Sampling taken from selected system test points and the bottom head drains of the heat exchangers are analyzed. The staff found that the applicant's extent of inspection scope and inspection schedule are adequate to detect the aging degradation in a timely manner prior to loss of component intended function.

Monitoring and Trending: The applicant stated that sampling and analysis are performed weekly to provide timely detection of aging degradation due to loss of material and cracking. The staff found the weekly sampling monitoring and analysis acceptable because it would provide timely detection of aging degradation and sufficient data for trending.

Acceptance Criteria: The acceptance criteria for the HPSW radioactivity monitoring activities AMP requires the absence of the radioactive contaminants in the system water. The staff found the acceptance criteria acceptable because loss of material and cracking in the tubes and tube sheets of the RHR heat exchangers can be identified by the presence of radioactive contaminants in the system water.

Operating Experience: The applicant identified the HPSW radioactivity monitoring activities AMP as an existing program. The applicant stated in Section B1.7 of the LRA that leakage and minor degradation have been found in the RHR heat exchangers on the HPSW system water (raw water) side. The degradation involved leakage of floating head gaskets, and degradation of internal baffle welds. Evaluations and adequate corrective actions, including gasket modifications were implemented prior to loss of intended function. The staff agreed that these activities are effective at maintaining the intended function of the structures and components that may be served by the HPSW radioactivity monitoring activities, and can reasonably be expected to do so for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff reviewed Section A1.7 of the UFSAR Supplement and found that the description of the applicant's HPSW radioactivity monitoring activities program is consistent with Section B1.7 of the LRA and is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

The staff has reviewed the information provided in Section B1.7 of the LRA and the summary description of the high pressure service water radioactivity monitoring activities in Section A1.7 of the UFSAR Supplement. On the basis of this review and the system and components discussed above, the staff found there is reasonable assurance the applicant has demonstrated that the system and components discussed above will be adequately managed so that there is reasonable assurance that this system will perform its intended function in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff has evaluated these AMPs and found them to be acceptable for managing the aging effects identified for the RHR system. On the basis of this review, the staff concludes that the applicant has provided adequate AMPs to manage the aging effects for these combinations of materials and environments and that the AMPs are consistent with published literature and industry experience.

3.2.5.3 Conclusions

The staff reviewed the information in LRA Section 3.2.5, “Residual Heat Removal System.” On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the RHR System will be adequately managed so that there is reasonable assurance that this system will perform its intended function in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.6 Containment Atmosphere Control and Dilution System

3.2.6 Technical Information in the Application

The applicant described its AMR of the containment atmosphere control and dilution system (CACDS) for license renewal in Section 3.2.6 and Table 3.2-6 of the LRA. The staff reviewed this section and table of the LRA to determine whether the applicant demonstrated that the effects of aging associated with the containment atmosphere control and dilution system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3). A complete list of the CACDS components requiring AMRs and the component intended functions is provided in Table 3.2-6 of the application.

3.2.6.1.1 Aging Effects

In Table 3.2-6 of the application, the applicant identifies the CACDS components subject to AMRs as pumps, valves, piping, and fittings. These components are fabricated from the following materials:

- carbon steel
- stainless steel
- brass
- aluminum

The applicant identifies these components as subject to any of the following environments:

- sheltered air
- dry gas
- wetted gas

The applicant describes the environmental conditions for these environments in Section 3.0 of the application.

The applicant identifies the following aging effects as applicable to the CACDS components:

- loss of material

3.2.6.1.2 Aging Management Programs

The applicant credits the following program for managing the aging effects attributed to the CACDS components within the scope of license renewal:

- primary containment leakage rate testing program

3.2.6.2 Staff Evaluation

The staff reviewed the component group, intended function, environments, materials of construction, aging effects, and aging management activity for the containment atmosphere control and dilution system in Table 3.2-6 of the LRA to determine whether the applicant has demonstrated that the effects of aging for this system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.6.2.1 Effects of Aging

Aging Effects for the Surfaces of CACDS Components Exposed to Gas Environments

The CACDS components include carbon steel valves and piping that are exposed to a wetted gas environment. In Table 3.2.6 of the LRA, the applicant identified loss of material as the applicable effect for the carbon steel CACDS components that are exposed to wetted gas. The applicant did not identify any applicable aging effects for the aluminum, brass, carbon steel, and stainless steel pumps, valves, piping, and fittings that are exposed to either dry gas or sheltered air environments.

The staff's evaluation of the applicant's omission of aging effects for the carbon steel CACDS components that are exposed to dry gas, sheltered air, or wetted gas environments is consistent with the staff's analysis in Section 3.2.1.2.1 for similar materials in the HPCI system. Based on the staff's evaluation in Section 3.2.1.2.1, the staff concludes the applicant has provided an acceptable basis for concluding no aging effects are applicable to the metallic CACDS piping components that are exposed to either sheltered air or ventilation atmosphere environments. The applicant's omission of aging effects for the metallic CACDS components in sheltered air or ventilation atmosphere environments is therefore acceptable to the staff.

3.2.6.2.2 Aging Management Programs

The applicant has credited the primary containment leakage rate testing program (LRA B.1.10) to manage loss of material in the CACDS components that are exposed to wetted gas. The staff evaluates this program in Section 3.0.3.8 of this SER. The staff has evaluated this AMP and has found it to be acceptable for managing the aging effects identified for CACDS. On the basis of this review, the staff concludes that the applicant has provided adequate AMPs to manage the aging effects for these combinations of materials and environments and that the AMPs are consistent with published literature and industry experience.

3.2.6.3 Conclusions

The staff has reviewed the information in Section 3.2.6, "Containment Atmosphere Control and Dilution System," of the LRA. On the basis of this review the staff concludes that the applicant has demonstrated that the aging effects associated with CACDS will be adequately managed so that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.7 Standby Gas Treatment System

3.2.7.1 Technical Information in the Application

The applicant described its AMR for the standby gas treatment system (SGTS) in Section 3.2, "Aging Management of Engineered Safety Features," and Table 3.2-7, "Standby Gas Treatment System," of the application. The staff reviewed these sections of the applications to determine whether the applicant has demonstrated that the effects of aging on the standby gas treatment system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3). A complete list of the SGTS components requiring AMRs and the component intended functions is provided in Table 3.2-7 of the application.

3.2.7.1.1 Aging Effects

In Table 3.2-7 of the application, the applicant identifies the major flowpaths of the SGTS as including the following components subject to AMRs: valve bodies, elastomer material flex connections and seals, piping (pipe, tubing, and fittings), pipe specialties (flow elements, pressure elements, and temperature element couplings), and sheet metal (plenums, fan enclosures, louvers, ductwork and damper enclosures). In this table, specific NS components are identified as fabricated from the following materials:

- carbon steel
- stainless steel
- neoprene
- bronze, brass, or copper
- anodized aluminum
- galvanized steel
- dielectric union materials

The applicant identifies the SGTS components as subject to any of the following environments:

- sheltered air
- ventilation atmosphere
- buried

The applicant describes these environments in Section 3.0 of the application.

The applicant identifies the following aging effects as applicable to the SGTS components:

- loss of material
- change in material properties

3.2.7.1.2 Aging Management Programs

The applicant credits the following programs and activities for managing the aging effects attributed to the SGTS components:

- Ventilation System Inspection and Testing Activities
- Outdoor, Buried, and Submerged Component Inspection Activities

Table 3.2-7 of the application identifies which of these programs will be used to manage the aging effects for the specific SGTS component materials and environmental condition combinations.

3.2.7.2 Staff Evaluation

The staff reviewed the component group, intended function, environments, materials of construction, aging effects, and aging management activities for the SGTS in Table 3.2-7 of the LRA to determine whether the applicant has demonstrated that the effects of aging for this system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.7.2.1 Effects of Aging

<u>Aging Effects for the Surfaces of SGTS Components Exposed to Gas Environments</u>

SGTS includes valve bodies, elastomer material flex connections and seals, piping (pipe, tubing, and fittings), pipe specialties (flow elements, pressure elements, and temperature element couplings), and sheet metal (plenums, fan enclosures, louvers, ductwork, and damper enclosures) that are fabricated from carbon steel, stainless steel, galvanized steel, copper alloy (including brass and bronze), galvanized aluminum, or neoprene materials. These components are exposed to either sheltered air or ventilation air conditions. In LRA Table 3.2-7, the applicant identified the following aging effect as applicable to the SGTS components that are exposed to gas environments:

- change in material properties for neoprene materials in sheltered air or ventilation atmosphere

The staff's evaluation of the applicant's omission of applicable aging effects for the metallic SGTS components that are exposed to sheltered air or ventilation atmosphere environments is similar to the staff's evaluation in Section 3.2.1.2.1 for metallic HPCI and other ESF components in these environments. Based on the staff's evaluation in Section 3.2.1.2.1, the staff concludes the applicant has provided an acceptable basis for concluding that aging effects are not applicable to the metallic SGTS piping, piping specialty, and sheet metal components that are exposed to either sheltered air or ventilation atmosphere environments. The applicant's omission of aging effects for the metallic SGTS components in sheltered air or ventilation atmosphere environments is therefore acceptable to the staff.

The staff's evaluation of the applicant's identification of applicable aging effects for the neoprene SGTS components that are exposed to sheltered air or ventilation atmosphere environments is consistent with the staff's evaluation in Section 3.2.1.2.1 for similar neoprene flex hose in the HPCI system in these environments. Based on the staff's evaluation in Section 3.2.1.2.1, the staff concludes that the applicant's identification of aging effects for the neoprene SGTS components that are exposed to either sheltered air or ventilation atmosphere environments is conservative and is therefore acceptable to the staff.

Aging Effects for the Surfaces of SGTS Components Exposed to Soil Environments

Some of the carbon steel SGTS piping is buried in the facility's soil. In LRA Table 3.2-7, the applicant identified the following aging effect as applicable to the SGTS components that are exposed to soil environments:

- loss of material for buried carbon steel

The buried environment is an additional environment associated with SGTS. Buried carbon steel SGTS piping is not specifically addressed in GALL Section V. The applicant stated that the buried environment consists of granular bedding material of sand or rock fines, backfill of dirt and rock, and filler material of gravel or crushed stone. Chemical testing of the groundwater has shown that the PBAPS soil has a pH ranging from 7.2 to 7.6, a chloride concentration ranging from 13.7 parts per million (ppm) to 21.5 ppm, and a sulfate concentration ranging from 10.3 ppm to 41 ppm. The applicant also assumed that the soil contains levels of oxygen, moisture(including ground water), biological organisms, and contaminants. The applicant identified that loss of material as an applicable aging effect for the buried SGTS piping. The conditions for the PBAPS soil may be conducive to general corrosion of the carbon steel piping buried in it. The staff therefore concurs that loss of material is an applicable effect for the exterior surfaces of buried carbon steel SGTS piping and concludes that the applicant's identification of aging effects for the SGTS buried piping is acceptable.

3.2.7.2.2 Aging Management Programs

The applicant will use the following programs for managing the aging effects that are applicable to the SGTS components:

- The applicant has credited the Ventilation System Inspection and Testing (LRA Section B.2.3) to manage the potential for the neoprene elastomeric materials to age over time and lose their elastomeric properties. The staff evaluates these activities in Section 3.0.3.12 of this SER.

- The applicant has credited the Outdoor, Buried, and Submerged Component Inspection (LRA Section B.2.5) to manage loss of material in buried SGTS carbon steel piping. The staff evaluates these activities in Section 3.0.3.13 of this SER.

The staff has evaluated these AMPs and has found them to be acceptable for managing the aging effects identified for SGTS. On the basis of this review, the staff concludes that the applicant has provided adequate AMPs to manage the aging effects for these combinations of materials and environments and that these AMPs are consistent with published literature and industry experience.

3.2.7.3 Conclusions

The staff reviewed the information in LRA Section 3.2.7, "Standby Gas Treatment System." On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with SGTS will be adequately managed so that there is reasonable assurance that this system will perform its intended function in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.8 Secondary Containment System

3.2.8.1 Technical Information in the Application

The applicant described its AMR of the secondary containment system (SCS) for license renewal in Section 3.2.8 and Table 3.2-8 of the LRA. The staff reviewed this section and table of the LRA to determine whether the applicant demonstrated that the effects of aging associated with the secondary containment system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3). A complete list of the SCS components requiring AMRs and the component intended functions is provided in Table 3.2-8 of the application.

3.2.8.1.1 Aging Effects

In Table 3.2-8 of the application, the applicant identifies the SCS components requiring AMRs as valves, tubing, and ducting. The components are fabricated from carbon steel, stainless steel, or galvanized steel.

The applicant identifies these components as subjected to either of the following environments:

- sheltered air
- ventilation atmosphere

The applicant describes the environmental conditions for these environments in Section 3.0 of the application.

The applicant does not identify any aging effects as applicable to the SCS components within the scope of license renewal.

3.2.8.1.2 Aging Management Programs

The applicant did not identify any aging effects as applicable to the SCS components within the scope of license renewal. The applicant therefore did not, in Table 3.2-8 of the application, identify any aging management programs for SCS.

3.2.8.2 Staff Evaluation

The staff reviewed the component group, intended function, environments, materials of construction, aging effects, and aging management activity for the secondary containment system in Table 3.2-8 of the LRA to determine whether the applicant has demonstrated that the effects of aging for this system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.8.2.1 Effects of Aging

<u>Aging Effects for the Surfaces of SCS Components Exposed to Gas Environments</u>

Sheltered air and ventilation atmosphere environments are the applicable environments for SCS. The applicant defines these environments in Section 3.0 of the application.

In Table 3.2-8, the applicant did not identify any aging effects as applicable to the SCS components that are exposed to sheltered air and ventilation environments.

The staff's evaluation of the applicant's omission of applicable aging effects for the metallic SCS components that are exposed to sheltered air or ventilation atmosphere environments is similar to the staff's evaluation in Section 3.2.1.2.1 for metallic HPCI and other ESF components under these environments. Based on the staff's evaluation in Section 3.2.1.2.1, the staff concludes the applicant has provided an acceptable technical basis for concluding that aging effects are not applicable to the metallic SCS components that are exposed to either sheltered air or ventilation atmosphere environments. The applicant's omission of aging effects for the metallic SCS components in sheltered air or ventilation atmosphere environments is therefore acceptable to the staff.

3.2.8.2.2 Aging Management Programs

The applicant did not credit any AMPs as being necessary for the SCS. Since the staff has concurred that there are no applicable aging effects for SCS, the staff also concurs that the applicant does not need to propose any AMPs for SCS.

3.2.8.3 Conclusions

The staff has reviewed the information in Section 3.2.8, "Secondary Containment System," of the LRA. On the basis of this review the staff concludes that the applicant has demonstrated that there are no aging effects associated with the SCS and that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3 Aging Management of Auxiliary Systems

3.3.0 General

3.3.0.1 Thermal Fatigue

The applicant did not identify cracking due to thermal fatigue as an aging effect requiring management in Section 3.3 for the auxiliary system components. Instead, the applicant identified thermal fatigue for piping systems designed to the requirements of ANSI B31.1 as a time-limited aging analysis (TLAA) in Section 4.3.3.2 of the LRA. The staff's evaluation of this TLAA is provided in Section 4.3.3 of this SER. Therefore, the aging effect due to thermal fatigue, as it applies to auxiliary system components, will not be discussed further in this section of the SER.

3.3.0.2 Crane Load Cycle Limit

In Sections 2.3.3.18 and 3.3.18 of the LRA, the applicant described the scope and the intended functions of cranes and hoists and the 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 the crane's design code, there is a specified load cycle limit at rated capacity over the projected life for the crane. Therefore, it is generally necessary to perform an evaluation of the TLAA relating to crane load cycles estimated to occur up to the end of the extended period of operation. The staff's evaluation of this TLAA is provided in Section 4.1.3 of this SER.

3.3.0.3 Ventilation Systems Flexible Connectors

Numerous ventilation systems discussed in Section 3.3 of the LRA include elastomer components. Ventilation systems contain elastomer materials in duct seals, flexible collars between ducts and fans, rubber boots, etc. For some plant designs, elastomer components are used as vibration isolators to prevent transmission of vibration and dynamic loading to the rest of the system. In Section 3.3 of the LRA, the applicant identified the component and aging effect of change in material properties for the elastomer components. To manage that aging effect, the applicant relies on the periodic visual inspection and testing activities included in the ventilation system inspection and testing activities AMP. 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. However, the aging effects of concern for those elastomer components are loss of material due to wear and changes in material properties such as hardening and loss of strength.

By letter dated February 6, 2002, per RAI 3.3-2, the staff requested that the applicant clarify whether it had considered the aging effect of loss of material due to wear for the applicable elastomer components. In addition, the applicant was requested to provide the frequency of the subject visual inspection and testing activities and to demonstrate the adequacy of the frequency of these inspection and testing activities to ensure that aging degradation will be detected before there is a loss of intended function.

The applicant responded to this RAI in a letter dated May 6, 2002. The applicant stated that based on plant operating experience and operating conditions, it determined that the applicable aging effect for elastomer components in the ventilation systems was change in material properties (loss of strength, resiliency, and elasticity). Loss of material due to wear was not identified as an applicable aging effect. The applicant also stated that components in the control room emergency ventilation system and the standby gas treatment system are inspected and tested annually. The inspection and testing for the battery room and emergency switchgear ventilation, control room fresh air supply, ES booster pump room and diesel generator room are performed every 2 years. The inspection and testing for the pump structure ventilation fans are performed every 4 years. The applicant further stated that the deficiencies noted in LRA Appendix B.2.3, "Ventilation System Inspection and Testing Activities", attribute number 10, had occurred before adequate preventive maintenance activities were instituted. No failures have been identified since the current inspection and testing activities have been instituted. Therefore, the applicant concluded that the existing inspection and testing activities and their associated frequencies are adequate to detect any aging effects prior to loss of intended function.

Based on the above discussion, the staff finds that the applicant's inspection and testing activities are based on the plants-specific operating experience and the associated frequencies are adequate to detect any aging effects prior to loss of intended function. Therefore, the AMP provides reasonable assurance that the plausible aging effect associated with the elastomer components, as it applies to the ventilation systems, will be adequately managed and is acceptable.

3.3.0.4 Scoping Issues Related to Aging Management Programs for Auxiliary Systems

The scoping requirements of 10 CFR 54.4(a)(2) include all non-safety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in 10 CFR 54.4(a)(1)(i), (ii), or (iii). 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, and operational factors 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. These effects, if not properly managed, could result in age-related failures and adversely impact the safety functions of safety-related SSCs.

By letter dated February 6, 2002, the staff requested additional information, per RAI 3.3-1, as to 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. Additionally, the applicant was requested to provide justification for not including the seismic II over I piping segments within the scope of license renewal. Specifically, the applicant was requested to address how plausible aging effects associated with those piping systems, if any, will be adequately managed.

The applicant responded to this RAI in a letter dated May 21, 2002. The applicant stated that a review was performed to identify non-safety-related piping systems and components whose failure could adversely impact the performance of an intended function of safety-related SSCs. As a result of this review, the applicant brought additional piping systems and components into the scope of license renewal. The staff's evaluation of the applicant's scoping and screening methodology for identifying those piping systems and components is described in Section 2.1.2.1.2 of this SER and will not be discussed further in this section of the SER. The staff's evaluation of these additional components identified as a result of the interactions of non-safety related systems with safety-related systems are discussed in Section 2.3.3.19 of this SER.

The applicant's response to the RAI also provides information regarding the management of aging effects associated with those additional non-safety-related piping systems and components that are brought into the scope of license renewal. The staff's evaluation of the applicant's aging management reviews, including the associated AMPs for those piping systems and components, is described in Section 3.3.0.7 of this SER and will not be discussed further in this section of the SER.

Based on the above discussion, the staff finds that the applicant's response clarifies and satisfactorily addresses staff's concern as described in RAI 3.3-1. The applicant's response provides reasonable assurance that plausible aging effects associated with seismic II over I SSCs, as they apply to auxiliary systems, will be adequately managed. The response is therefore, acceptable.

3.3.0.5 Flow Blockage

In several of the Auxiliary systems listed in Section 3.3, the internal surfaces of stainless steel, carbon steel, and cast iron components are exposed to a raw water environment. Typically, fouling is the aging effect associated with a raw water environment. In a letter dated February 6, 2002, the staff requested additional information per RAI 3.3-6 to discuss fouling as an aging effect. By letter dated May 6, 2002, the applicant stated that fouling is classified as “flow blockage” in the Peach Bottom 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 system (LRA Section 3.3.6) and the emergency cooling water systems (LRA Section 3.3.14).

The staff finds that the applicants response clarifies and adequately addresses the issue.

3.3.0.6 Carbon Steel in a Sheltered Environment

In several of the Auxiliary systems listed in Section 3.3, the applicant stated that carbon steel piping, tubing, and other components are exposed to a sheltered environment. Typically, loss of material is a potential aging effect for the combination of material and environment due to possible rusting caused by varied levels of moisture in a sheltered environment. However, the applicant did not identify loss of material as an aging effect. In most cases, carbon steel piping, tubing, and other components are either painted or insulated. Loss of material is not applicable to painted components. For insulated components, since the temperature is higher than ambient, the surfaces are not exposed to moisture and, therefore, are not susceptible to loss of material. In rare cases where carbon steel components are not painted, the surfaces are subject to possible rusting. However, surface rusting generally will not adversely impact the function of the components during the life of the plant. This is consistent with the industry operating experience. This topic is also discussed in Section 3.2.1.2.1 of this SER.

Based on the above discussion, the staff agrees with the applicant’s conclusion that, for carbon steel components exposed to a sheltered environment, loss of material is not an aging effect significant enough to warrant an aging management program.

3.3.0.7 Review of Added Items Due to Expanded Scope

During its review of the Peach Bottom LRA, the staff forwarded to the applicant three requests for additional information (RAIs) related to non-safety-related (NSR) piping systems which are connected to safety-related (SR) piping but have a spatial relationship such that their failure could adversely impact the intended safety function. The RAIs (RAIs 2.1.2-3, 2.1.2-4, and 3.3-1) were transmitted to the applicant in order to obtain information about this issue and thus ascertain that NSR piping in spatial proximity to SR piping would not adversely affect the safety-related function of systems that are within the scope of license renewal. The applicant included Tables 2.1.2-3-1 and 2.1.2-3-2 in its response to the staff’s RAIs. Table 2.1.2-3-1 expanded the system boundary for systems already within the scope of license renewal to include portions of systems that are not safety-related. Table 2.1.2-3-2 listed additional systems that were included within the scope of license renewal to meet the 10 CFR 54.4(a)(2) criteria. The tables also documented the results of the applicant’s evaluation of components included within the expanded and additional systems that were added as a result of the staff's RAIs. The applicant identified the following systems that were affected by the change to the scope of license renewal:

- reactor coolant system
- engineered safety feature systems
- auxiliary systems

In its response to the staff's RAIs, the applicant also provided information regarding management of aging effects associated with those additional non-safety-related piping segments brought into the scope of license renewal. The applicant is using the reactor coolant system chemistry program, closed cooling chemistry program, condensate storage tank chemistry activities program, torus water chemistry activities program, fuel pool chemistry activities program, and the one-time piping inspection activities program to manage the aging effects identified for these additional components. The staff verified that the added scope did not include new and unique materials and aging effects, and that the applicant is using the above-listed aging management programs to manage the identified aging effects. The staff's review of the above-mentioned aging management programs is included in Section 3.0 of this SER. On the basis of its review of the additional information provided by the applicant, the staff concludes that the aging management of NSR piping in the spatial proximity to SR piping will be adequately monitored and managed so that the safety release function of the SR piping will be ensured during the period of extended operation.

3.3.1 Fuel Handling System

3.3.1.1 Technical Information in the Application

The technical information is presented in Section 2.3.3.1 and Table 3.3-1 of the LRA. The component groups for the fuel handling systems include fuel preparation machines, the refueling platform, the refueling rails, and the refueling mast.

The fuel handling system consists of the refueling platform equipment assembly and the fuel preparation machines. The Unit 2 and 3 refueling floors are physically separated. Each unit has its own fuel handling system and fuel pool. The refueling platform includes a bridge structure that spans the spent fuel pool and the reactor well. The platform travels on rails that extend the length of the fuel storage pool and the reactor well. A working platform extends the width of the bridge structure, providing working access to the entire width of the pools and the reactor well area.

Two fuel preparation machines located in each fuel storage pool are used to strip the channels from spent fuel assemblies and to install the used channels on new fuel assemblies.

The refueling platform assembly and fuel preparation machines are constructed from stainless steel, aluminum, and carbon steel and the rails are constructed from carbon steel.

3.3.1.1.1 Aging Effects

The components of the fuel handling system are described in Section 2.3.3.1 of the submittal. These components are within the scope of license renewal and are subject to an aging management review. Table 3.3-1 of the LRA lists individual components of the system, including fuel preparation machines, refueling platform assembly, rails, and mast. Stainless steel and aluminum components are identified as being subject to loss of material from exposure to the fuel pool water. Stainless steel and carbon steel exposed to sheltered environments have no associated aging effects.

3.3.1.1.2 Aging Management Programs

The following AMP is utilized to manage aging effects for the fuel handling system:

- fuel pool chemistry activities

A description of the aging management program activities is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the fuel handling system will be adequately managed by the aging management program such that there is reasonable assurance that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.3.1.2 Staff Evaluation

The staff reviewed the application to determine whether the applicant has demonstrated that the effects of aging on these component groups will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.1.2.1 Aging Effects

The fuel preparation machines are fabricated from stainless steel and aluminum and are exposed to fuel pool water.

The refueling platform assembly is constructed from stainless steel and carbon steel and the rails are constructed from carbon steel. They are exposed to a sheltered environment. There were no aging effects identified and, as a result, no aging management activity is required. The staff agrees with the applicant’s conclusion that there are no credible aging effects for stainless steel and carbon steel in a sheltered environment.

The refueling platform mast is constructed from stainless steel and chromiu- plated stainless steel exposed to fuel pool water. The applicant identified loss of material as the aging effect. The aging effect of the SSCs in the fuel handling system exposed to the environments identified in the LRA are consistent with industry experience. The staff finds that the aging effects identified are appropriate.

3.3.1.2.2 Aging Management Programs

Section 2.3.3.1 and Table 3.3-1 of the LRA state that the following aging management program is credited for managing the aging effects in the fuel handling system:

- fuel pool chemistry activities

The staff finds that the fuel pool chemistry activities are effective in controlling loss of material for these component groups. The staff review of the fuel pool chemistry activities follows.

3.3.1.3 Conclusions

The staff has reviewed the information on aging effects and aging management activities for the materials and environments of the fuel handling equipment, and the staff concludes that the applicant has demonstrated that aging effects associated with the subject components will be adequately managed so there is reasonable assurance that the subject system will perform its intended functions in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.2 Fuel Pool Cooling and Cleanup System

3.3.2.1 Technical Information in the Application

The aging management review results for the fuel pool cooling and cleanup system are presented in Table 3.3-2 of the LRA.

Section 2.3.3.2 of the LRA states that the fuel pool cooling and cleanup system provides fuel pool water temperature control and is used to maintain fuel pool water clarity, purity, and level. The fuel pool cooling and cleanup system cools the fuel storage pool by transferring decay heat through the heat exchangers to the service water system. Water purity and clarity in the fuel storage pool, reactor well, and steam dryer-separator storage pit are maintained by filtering and demineralizing the pool water.

The system consists of three fuel pool cooling pumps, three heat exchangers, a filter demineralizer, two skimmer surge tanks, and associated piping and valves. The three fuel pool cooling pumps are connected in parallel, as are the three heat exchangers. The pumps and heat exchangers are located in the reactor building. An interconnection with the RHR system provides backup cooling and makeup water to the fuel storage pool.

Piping and components required to support fuel pool makeup from the RHR system are the only part of the system in scope for this application.

3.3.2.1.1 Aging Effects

In Table 3.3-2 of the LRA, the applicant identifies the following components that will require aging management: valve bodies, piping, tubing, vacuum breakers, and restricting orifices. The applicant identified stainless steel and carbon steel as the materials of construction for the fuel pool cooling and cleanup system. Loss of material and cracking were identified as applicable aging effects for stainless steel exposed to the fuel pool water. Loss of material was identified as an applicable aging effect for carbon steel components exposed to the fuel pool water.

3.3.2.1.2 Aging Management Programs

The LRA identifies the fuel pool chemistry activities as the aging management program that will manage the aging effects of the fuel pool cooling and cleanup system. A description of the fuel pool chemistry activities is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with components of the fuel pool cooling and cleanup system will be adequately managed by this aging management program such that there is reasonable assurance that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.3.2.2 Staff Evaluation

The staff reviewed Section 2.3.3.2 and Table 3.3-2 of the LRA to determine whether the applicant has demonstrated that the effects of aging on these component groups will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.2.2.1 Aging Effects

The fuel pool cooling and cleanup system contains castings and forgings (valve bodies), piping and piping specialities (vacuum bivalve and restricting orifices) constructed from carbon steel and stainless steel which are exposed to fuel pool water. The carbon steel components and stainless steel components are susceptible to the aging effect loss of material. The stainless steel components are also susceptible to cracking.

The aging effects of the SSCs in the fuel pool cooling and cleanup system exposed to the environments the applicant identified in the LRA are consistent with industry experience. The staff finds that the aging effects identified are appropriate.

3.3.2.2.2 Aging Management Programs

The loss of material and the cracking aging effects are managed by the fuel pool chemistry activities. The staff agrees that the fuel pool chemistry activities are adequate to manage the aging effects, loss of material and cracking of stainless steel and carbon steel exposed to fuel pool water. The staff review of the fuel pool chemistry activities is documented above in Section 3.3.1.2.2.

Based on industry experience, there are no aging effects for stainless steel and carbon steel pipe exposed to a sheltered environment, and no aging management programs are required.

3.3.2.3 Conclusions

The staff has reviewed the information on aging effects and aging management activities for the materials and environments of the fuel pool cooling and cleanup components. The staff concludes that the applicant has demonstrated that aging effects associated with the subject components will be adequately managed so there is reasonable assurance that the subject system will perform its intended functions in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.3 Control Rod Drive System

3.3.3.1 Technical Information in the Application

The aging management review results for the control rod drive system are presented in Table 3.3-3 of the LRA.

Section 2.3.3.3 of the LRA states that the control rod drive (CRD) system is a reactivity control system that utilizes pressurized demineralized water to rapidly insert control rods in the core upon receipt of a scram signal. The system also provides control rod manipulation and positioning for power adjustments, and serves as a source of cooling water for the graphitar seals of the CRD mechanisms.

The CRD system serves as a source of purge water for the reactor water cleanup pumps and reactor recirculation pump seals. The system also serves as a source of injection water to reactor vessel level instrumentation reference legs to mitigate the accumulation of gases.

The alternate rod insertion (ARI) system is a subsystem of the CRD system and serves as a backup means to provide a reactor scram, independent of the reactor protection system, by venting off the scram air header. The ARI function serves to reduce the probability of an ATWS event and may be initiated automatically or manually.

The components in this system are fabricated from carbon steel and stainless steel.

3.3.3.1.1 Aging Effects

Table 3.3-3 of the LRA identifies the following components that will require aging management: valve bodies, piping, tubing, filter bodies, rupture discs, and accumulators. The applicant identified stainless steel and carbon steel as the materials of construction for the CRD system. Loss of material was identified as an applicable aging effect for carbon steel components exposed to condensate storage water. Loss of material and cracking were identified as applicable aging effects for stainless steel materials exposed to condensate storage water.

3.3.3.1.2 Aging Management Programs

The LRA identifies the following two aging management programs that will manage the aging effects of the CRD system:

- condensate storage tank chemistry activities
- ISI program

Appendix B of the LRA contains a detailed description of the subject aging management programs. The LRA cites these programs for managing aging effects of the CRD system components in applicable environments.

3.3.3.2 Staff Evaluation

The staff reviewed Section 2.3.3.3 and Table 3.3-3 of the LRA to determine whether the applicant has demonstrated that the effects of aging on these component groups will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.3.2.1 Aging Effects

The control rod drive system contains castings and forgings (valve bodies) constructed of stainless steel and exposed to condensate storage water. The applicant has identified two aging effects for these components, loss of material and cracking.

The control rod drive system contains castings and forgings (valve bodies) constructed of carbon steel and stainless steel and exposed to a sheltered environment. No aging effects were identified. Therefore, no aging management program is required. The staff agrees that for these materials and environment, there are no identified aging effects requiring management.

The control rod drive system contains castings and forgings (valve bodies) constructed from carbon steel and exposed to wetted gas. The applicant identified loss of material as the aging effect.

The control rod drive system contains piping (pipe and tubing) constructed from stainless steel and exposed to condensate storage water. The applicant identified loss of material and cracking as the aging effects requiring management.

The control rod drive system contains piping (pipe and tubing) constructed from carbon steel and stainless steel and exposed to dry gas and to a sheltered environment. There are no identified aging effects.

The control rod drive system contains piping (pipe) constructed from carbon steel and exposed to wetted gas. The applicant identified loss of material as the aging effect.

The control rod drive system contains piping specialities (filter bodies) constructed from stainless steel and exposed to condensate storage water. The applicant identified loss of material and cracking as the applicable aging effects.

The control rod drive system contains piping specialities (rupture disc) constructed from carbon steel and stainless steel and exposed to dry gas. The applicant identified no aging effects requiring management, and hence credits no aging management activities for this component.

The control rod drive system contains piping specialities (filter bodies and rupture disc) constructed from carbon steel and stainless steel and exposed to a sheltered environment. The applicant identified no aging effects requiring management, and hence credits no aging management activities for this component. The staff agrees that for these materials and environment combination there are no aging effects requiring management.

The control rod drive system contains accumulators constructed from carbon steel and stainless steel and exposed to condensate storage water. The applicant identified loss of material as an aging effect for the carbon steel and loss of material and cracking as the aging effect for stainless steel.

The control rod drive system contains accumulators constructed from carbon steel and stainless steel and exposed to dry gas and a sheltered environment. The applicant identified no aging effects requiring management. The staff agrees that for this material and environment combination, there are no aging effects requiring management.

The aging effects of the SSCs in the control rod drive system exposed to the environments the applicant identified in the LRA are consistent with industry experience. The staff finds that the aging effects identified are appropriate.

3.3.3.2.2 Aging Management Programs

The applicant identified the following two aging management programs that will manage the aging effects for the control rod drive system:

- condensate storage tank chemistry activities
- ISI activities

The CST chemistry activities are reviewed in Section 3.0.3.4 of this SER. The staff agrees with the effects of aging identified by the applicant and agrees that the CST chemistry activities are the adequate aging management activities.

The ISI program is reviewed in Section 3.0.3.6 of this SER. The staff agrees that loss of material is the appropriate aging effect for these material and environment combinations and that the ISI program will adequately manage this aging effect for the period of extended operation.

3.3.3.3 Conclusions

The staff has reviewed the information on aging effects and aging management activities for the material/environment combinations for the control rod drive system. The staff concludes that the applicant has demonstrated that aging effects associated with the subject components will be adequately managed so there is reasonable assurance that the subject system will perform its intended functions in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.4 Standby Liquid Control System

3.3.4.1 Technical Information in the Application

The technical information regarding the standby liquid control system is presented in Section 2.3.3.4 and Table 3.3-4 of the LRA. The purpose of the standby liquid control system is to provide a backup method, which is redundant to, and independent of, the control rod drive system to shut down the reactor and maintain it in a cold, subcritical condition. Maintaining subcriticality as the nuclear system cools assures that the fuel barrier is not threatened by overheating in the event that not enough of the control rods can be inserted to counteract the positive reactivity effects of a decrease in the moderator temperature. A neutron absorber consisting of enriched sodium pentaborate in solution is injected into the vessel and distributed throughout the core in sufficient quantity to achieve and maintain shutdown while allowing for margin due to leakage and imperfect mixing. The system is manually initiated from the control room via a three-position key-locked selector switch.

3.3.4.1.1 Aging Effects

The components of the standby liquid control system are described in Section 2.3.3.4 of the submittal as being within the scope of license renewal and subject to aging management review. Table 3.3-4 of the LRA lists individual components of the system, including a solution storage tank, a test tank, two 100%-capacity positive displacement pumps with their associated relief valves and accumulators, two explosive valves installed in parallel, and associated controls and instrumentation. The components of the standby liquid control system are fabricated from carbon steel and stainless steel.

A description of the environments is provided in Table 3.3-4 of the LRA. The standby liquid control system structures and components are exposed to the following environments:

- borated water
- dry gas
- reactor coolant
- sheltered

The following aging effects associated with the structures and components require aging management:

- cracking of stainless steel components in borated water environments
- cracking of stainless steel components in reactor coolant environments
- loss of material from carbon steel and stainless steel components in borated water environments
- loss of material from carbon steel and stainless steel components in reactor coolant environments

3.3.4.1.2 Aging Management Programs

The following aging management activities manage aging effects for the standby liquid control system structures and components:

- RCS Chemistry
- Deminerlized Water and Condensate Storage Tank Chemistry Activities
- Standby Liquid Control System Surveillance
- ISI Program
- One-Time Piping Inspection Activities

Descriptions of these aging management programs are provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the standby liquid control system will be adequately managed by these aging management programs such that there is reasonable assurance that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.3.4.2 Staff Evaluation

The applicant described its AMR of the standby liquid control system for license renewal in Section 2.3.3.4 and Table 3.3-4 of the LRA. The staff reviewed is section and of the LRA to determine whether the applicant has demonstrated that the effects of aging on the standby liquid control system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.4.2.1 Aging Effects

The components of the standby liquid control system are fabricated from carbon steel and stainless steel.

Some pump, valve, piping, and tubing components that are made of carbon steel and stainless steel are exposed to a borated water environment. The aging effects associated with exposure to borated water are identified in Table 3.3.4 of the LRA. The applicable aging effects are loss of material and cracking due to chemical attack. Cracking of stainless steel in borated water is an aging effect that needs to be managed by appropriate AMPs. Loss of material of carbon steel in borated water is identified as an aging effect and will be managed by AMPs. Loss of material of stainless steel components in borated water is also identified by the applicant as an aging effect. The staff believes this aging effect is insignificant and unlikely to occur. However, since the applicant’s position is more conservative, the staff agrees with the applicant’s review for this combination of material and environment.

The components of the standby liquid control system which are exposed to a sheltered environment are fabricated from stainless steel and carbon steel. The sheltered environment consists of a moist, atmospheric air with a temperature ranging from 65°F to 150°F and a relative humidity ranging from 10% to 90%. The aging effect discussion for these materials is provided in Section 3.3.0.6 of this SER.

The aging effects that result from the contact of standby liquid control system structures and components with the environments listed in Table 3.3-4 are consistent with industry experience for these combinations of materials and environments. The staff finds that the aging effects identified are appropriate for the combinations of materials and environments listed.

3.3.4.2.2 Aging Management Programs

As shown in Section 2.3.3.4 and Table 3.3-4 of the LRA, the following aging management programs are credited for managing the aging effects in the standby liquid control system:

The applicant modified the aging management activities associated with the standby liquid control system. By letter dated May 14, 2002, the applicant stated that the modified managing approach for the standby liquid control system includes water chemistry controls applied to the demineralized water system and a one-time inspection of a representative section of standby liquid control system piping. These AMPS are discussed in Section 3.0.3 of this SER. Therefore, App 3.1.13 of the Standby Liquid Control System Service Activities AMP in the LRA was deleted. A detailed discussion is provided in Section 3.0.3.19 of this SER.

- RCS Chemistry
- Demineralized Water and Condensate Storage Tank Chemistry Activities
- ISI Program

- One-Time Piping Inspection Activities

The RCS Chemistry Program activities are a preventive aging management program that assures potentially detrimental concentrations of impurities are not present in the reactor coolant. The program manages loss of material and cracking in components exposed to reactor water and steam.

The demineralized water and CST chemistry activities manage loss of material of carbon steel and stainless steel components and cracking of stainless steel components exposed to CST water or demineralized water in the standby liquid control system.

The ISI program provides for visual inspection of selected surfaces of specific components and structural components, or alternatively their replacement/refurbishment during the performance of periodic surveillance and preventive maintenance activities. The program provides for condition monitoring of pressure-retaining piping and components in the scope of license renewal except for those components covered by the reactor pressure vessel and internals ISI program.

The one-time piping inspection activities AMP (in conjunction with the demineralized water and condensate storage tank chemistry AMP) is used by PBAPS to manage loss of material and cracking in components that contain or are exposed to demineralized water (including borated water) or condensate storage water. This program is also used to confirm the effectiveness of the water chemistry programs in managing the effects of aging in the standby liquid control system. This activity consists of a one-time inspection of selected system piping to verify the integrity of the piping and confirm the absence of identified aging effects.

The RCS Chemistry Program, demineralized water and CST chemistry activities, ISI Program, and one-time piping inspection activities are credited with managing the aging effects of several components in various different structures and systems and are, therefore, considered common aging management programs. Descriptions of these programs are provided in Appendix B of the LRA. The staff review of the common aging management programs is in Section 3.0 of this SER.

3.3.4.3 Conclusions

The staff reviewed the information in Section 2.3.3.4 and Table 3.3-4 of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the standby liquid control system structures and components will be adequately managed so that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.5 High-Pressure Service Water System

3.3.5.1 Technical Information in the Application

The technical information regarding the high-pressure service water system is presented in Section 2.3.3.5 and Table 3.3-5 of the LRA. The high-pressure service water system provides cooling water for the residual heat removal system heat exchangers under normal, hot standby, refueling and post-accident conditions. The system provides core decay heat removal capability during shutdown periods, and containment cooling during normal operations and during post-accident conditions.

3.3.5.1.1 Aging Effects

The components of the high-pressure service water system are described in Section 2.3.3.5 of the submittal as being within the scope of license renewal and subject to aging management review. Table 3.3-5 of the LRA lists individual components of the system, including heat exchangers, pumps, and the necessary piping, tubing, valves, and controls. The components are made of carbon steel, cast iron, copper, alloy, and stainless steel.

A description of the environments is provided in Table 3.3-5 of the LRA. The High-pressure service water system structures and components are exposed to the following environments:

- outdoor
- raw water
- buried
- lube oil
- sheltered

The following aging effects associated with the structures and components require aging management:

- cracking of stainless steel and copper components in raw water environments
- loss of material from carbon steel in outdoor environments
- loss of material from carbon steel, cast iron, stainless steel, and alloy steel components in raw water environments
- flow blockage of carbon steel, cast iron, stainless steel, and copper components in raw water environments
- cracking of cast iron and copper components in lube oil environments
- heat transfer reduction of copper in lube oil environments
- heat transfer reduction of cast iron in raw water environments
- loss of material from carbon steel in buried environments

3.3.5.1.2 Aging Management Programs

The following aging management activities manage aging effects for the High-pressure service water system structures and components:

- Outdoor, Buried, and Submerged Component Inspection Activities
- Generic Letter 89-13 Activities
- Lubricating and Fuel Oil Quality Testing
- ISI Program

Descriptions of these aging management programs are provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the High-Pressure Service Water System will be adequately managed by these aging management programs such that there is reasonable assurance that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.3.5.2 Staff Evaluation

The applicant described its AMR of the high-pressure service water system for license renewal in Section 2.3.3.5 and Table 3.3-5 of the LRA. The staff reviewed this section and of the LRA to determine whether the applicant has demonstrated that the effects of aging on the High-Pressure Service Water System will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.5.2.1 Aging Effects

The components of the high-pressure service water system are heat exchangers, pumps, piping, tubing, valves, and controls, and are made of carbon steel, cast iron, copper, alloy, and stainless steel.

Valve, piping, and tubing components made of carbon steel are exposed to a raw water environment. The aging effects associated with exposure to raw water are identified in Table 3.3.5 of the LRA. The applicable aging effects are loss of material and flow blockage due to chemical attack and fouling.

Some components made of stainless steel are exposed to a raw water environment. The applicable aging effects are cracking and flow blockage due to chemical attack and fouling.

Pump casings made of cast iron are exposed to a raw water environment. The aging effects associated with exposure to raw water are loss of material and flow blockage.

Some pump casings made of cast iron or copper are also exposed to a lubricating oil environment. The aging effects associated with exposure to this environment are cracking and heat transfer reduction.

Heat exchanger tubing made of copper is exposed to a raw water environment. The aging effects associated with exposure to raw water are identified in Table 3.3.5 of the LRA. The applicable aging effects are cracking, heat transfer reduction, and flow blockage.

The aging effects that result from the contact of High-pressure service water system structures and components with the environments shown in Table 3.3-5 are consistent with industry experience for these combinations of materials and environments. The staff finds that the aging effects identified above are appropriate for the combinations of materials and environments listed.

3.3.5.2.2 Aging Management Programs

As shown in Section 2.3.3.5 and Table 3.3-5 of the LRA, the following aging management programs are credited for managing the aging effects in the High-pressure service water system:

- Outdoor, Buried, and Submerged Component Inspection Activities

- Generic Letter 89-13 Activities
- Lubricating and Fuel Oil Quality Testing
- ISI Program

The Outdoor, Buried, and Submerged Component Inspection activities detect degradation due to loss of material or cracking of external surfaces for outdoor, buried, and submerged components. The program is implemented in accordance with PBAPS maintenance procedures and routine test procedures that provide instructions for visual inspections.

The GL 89-13 activities include both condition monitoring and mitigating activities for managing aging effects for the components of the HPSW, ESW, ECW, and other systems that use raw water as a cooling medium. System and component testing, visual inspections, UT, and biocide treatments are conducted to ensure that aging effects are managed such that system and component intended functions are maintained. The program manages loss of material, cracking, flow blockage, and heat transfer reduction aging effects in cooling water piping and components that are tested and inspected in accordance with the guidelines of NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment."

Lubricating and Fuel Oil Quality Testing Program manages loss of material, cracking, and heat transfer reduction in components that contain or are exposed to lubricating oil or fuel oil. It is implemented through PBAPS procedures and includes sampling and analysis of lubricating oil and fuel oil for detrimental contaminants. The program provides preventive aging management activities that assure potentially detrimental concentrations of water and particulate are not present in the oil. These activities also provide for detection of loss of material and cracking in certain components containing lubricating or fuel oil.

The ISI program provides for visual inspection of selected surfaces of specific components and structural components, or alternatively their replacement/refurbishment during the performance of periodic surveillance and preventive maintenance activities. The program provides for condition monitoring of pressure retaining piping and components in the scope of license renewal except for those components covered by the reactor pressure vessel and internals ISI program.

The Outdoor, Buried, and Submerged Component Inspection Activities Program, Generic Letter 89-13 Activities Program, Lubricating and Fuel Oil Quality Testing Program, and ISI Program are credited with managing the aging effects of several components in various different structures and systems and are, therefore, considered common aging management programs. Descriptions of these programs are provided in Appendix B of the LRA. The staff's review of the common aging management programs is in Section 3.0 of the SER.

3.3.5.3 Conclusions

The staff reviewed the information in Section 3.3.5 and Table 3.3-5 of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the High-pressure service water system structures and components will be adequately managed so that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.6 Emergency Service Water System

3.3.6.1 Technical Information in the Application

The technical information regarding the emergency service water system is presented in Section 2.3.3.6 and Table 3.3-6 of the LRA. The emergency service water system provides a reliable supply of cooling to diesel generator coolers, emergency core cooling system and reactor core isolation cooling compartment air coolers, core spray pump motor oil coolers, and other equipment during a loss of offsite power or during a loss of normal station service water.

A return header in each unit returns the water to the discharge pond or the emergency cooling water system. During normal operations, all system loads with the exception of the emergency diesel generator heat exchangers are supplied with cooling water from the service water system. The emergency service water system provides the cooling water whenever the pumps are operating and the emergency service water system pressure is greater than service water system pressure or the service water system is manually isolated from the emergency service water system. In the event of extreme high or low Conowingo Pond level, the emergency service water system can be shifted to closed cycle operation through the use of the emergency cooling water system.

3.3.6.1.1 Aging Effects

The components of the emergency service water system are described in Section 2.3.3.6 of the submittal as being within the scope of license renewal and subject to aging management review. Table 3.3-6 of the LRA lists individual components of the system, including two 100%-capacity ESW pumps and the associated discharge and distribution piping, piping components, valves, and instrumentation and controls. These components are made of carbon steel, copper, alloy steel, and stainless steel.

The environments are described in Table 3.3-6 of the LRA. The emergency service water system structures and components are exposed to the following environments:

- outdoor
- raw water
- buried
- sheltered

The following aging effects associated with the structures and components require aging management:

- cracking of stainless steel and copper components in raw water environments
- loss of material from carbon steel in outdoor environments
- loss of material from carbon steel, cast iron, stainless steel, and alloy steel components in raw water environments
- flow blockage of carbon steel, cast iron, stainless steel, and copper in raw water environments
- loss of material from carbon steel in buried environments

3.3.6.1.2 Aging Management Programs

The following aging management activities manage aging effects for the emergency service water system structures and components:

- Outdoor, Buried, and Submerged Component Inspection Activities
- Generic Letter 89-13 Activities
- ISI Program
- Inservice Testing (IST) Program

These aging management programs are described in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the emergency service water system will be adequately managed by these aging management programs such that there is reasonable assurance that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.3.6.2 Staff Evaluation

The applicant described its AMR of the emergency service water system for license renewal in Section 2.3.3.6 and Table 3.3-6 of the LRA. The staff reviewed this section and table of the LRA to determine whether the applicant has demonstrated that the effects of aging on the emergency service water system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.6.2.1 Aging Effects

The Emergency Service Water (ESW) System consists of two ESW pumps and associated discharge and distribution piping, piping components, valves, and instrumentation and controls. These components are made of carbon steel, copper, alloy steel, and stainless steel.

Valve, piping, and tubing components made of carbon steel and valve bodies and pump casings made of cast iron are exposed to a raw water environment. The aging effects associated with exposure to raw water are identified in Table 3.3.6 of the LRA. Applicable aging effects include loss of material and flow blockage due to chemical attack and fouling.

Some components made of stainless steel are exposed to a raw water environment. The aging effects associated with exposure to raw water are identified in Table 3.3.6 of the LRA. Applicable aging effects include loss of material, cracking, and flow blockage due to chemical attack and fouling.

Some carbon steel piping is exposed to a buried environment. The aging effect associated with exposure to this environment is loss of material.

The possible aging effects for copper piping exposed to raw water are loss of material, cracking, and flow blockage.

Loss of material and flow blockage are the applicable aging effects for piping made of alloy steel exposed to a raw water environment.

The aging effects that result from the contact of emergency service water system structures and components with the environments identified in Table 3.3-6 are consistent with industry experience for these combinations of materials and environments. The staff finds that the aging effects identified are appropriate for the combinations of materials and environments listed.

3.3.6.2.2 Aging Management Programs

As shown in Section 2.3.3.6 and Table 3.3-6 of the LRA, the following aging management programs are credited for managing the aging effects in the emergency service water system:

- Outdoor, Buried, and Submerged Component Inspection Activities
- Generic Letter 89-13 Activities
- ISI Program
- Inservice Testing (IST) Program

The Outdoor, Buried, and Submerged Component Inspection activities detect degradation due to loss of material or cracking of external surfaces for outdoor, buried, and submerged components. The program is implemented in accordance with PBAPS maintenance procedures and routine test procedures that provide instructions for visual inspections.

The GL 89-13 activities include both condition monitoring and mitigating activities for managing aging effects in the HPSW, ESW, and ECW systems and in other components using raw water as a cooling medium. System and component testing, visual inspections, UT, and biocide treatments are conducted to ensure that aging effects are managed such that system and component intended functions are maintained. The program manages loss of material, cracking, flow blockage, and heat transfer reduction aging effects in cooling water piping and components that are tested and inspected in accordance with the guidelines of NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-related Equipment."

The ISI program provides for visual inspection of selected surfaces of specific components and structural components, or alternatively their replacement/refurbishment during the performance of periodic surveillance and preventive maintenance activities. The program provides for condition monitoring of pressure-retaining piping and components in the scope of license renewal except for those components covered by the reactor pressure vessel and internals ISI program.

The IST program is implemented by a PBAPS specification and provides for inservice testing of Class 1, 2, and 3 pumps and valves in compliance with the ASME O&M Code. The program manages flow blockage in the ESW and ECW components that are exposed to raw water that can lead to a reduction in heat transfer through the RHR heat exchangers.

The Outdoor, Buried, and Submerged Component Inspection Activities Program, Generic Letter 89-13 Activities Program, and Inservice Testing (IST) Program and ISI Program are credited with managing the aging effects of several components in various different structures and systems and are, therefore, considered common aging management programs. A description of these programs is provided in Appendix B of the LRA. The staff review of the common aging management programs is in Section 3.0 of this SER.

3.3.6.3 Conclusions

The staff reviewed the information in Section 3.3.6 and Table 3.3-6 of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the emergency service water system structures and components will be adequately managed so that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.7 Fire Protection System

3.3.7.1 Technical Information in the Application

The fire protection system contains components and equipment for detecting, suppressing, containing, and monitoring fires. This system includes various types of water, foam, and carbon dioxide suppression systems and has active and passive features such as fire doors and fire dampers that prevent a fire from spreading from one area of the plant to another. Two vertical turbine fire pumps — one diesel, one electric — take their suction from independent, isolable intake wells and can provide water from Conowingo Pond.

The components of the fire protection system are described in Section 2.3.3.7 of the LRA as being within the scope of license renewal and subject to aging management review (AMR). The materials of construction of the fire protection system components are cast iron, carbon steel, bronze, aluminum, stainless steel, brass, copper, brass alloys, chrome-plated brass, and malleable iron. Table 3.3-7 of the LRA lists the individual components of the system, including valve bodies, sprinkler heads, strainer screens, pump casings, hydrants, pipe, tubing, fittings, discharge nozzles, strainer bodies, restricting orifices, flow elements, flexible hoses, metal flex connections, Y strainer bodies, Cardox tanks, fuel tanks, and mufflers.

3.3.7.1.1 Aging Effects

The applicant identified no aging effects for cast iron, carbon steel, bronze, aluminum, stainless steel and brass components in the sheltered and dry gas environment and no aging effects for copper, brass alloys, chrome-plated brass, and malleable iron in the sheltered environment or carbon steel, malleable iron, and bronze components in the outdoor environment. The applicant identified aging effects for the following combinations of component materials and internal/external environments:

- loss of material and flow blockage for cast iron in buried, fuel oil, outdoor, and raw water environments
- loss of material and flow blockage for lined cast iron in buried and raw water environments
- cracking, loss of material and flow blockage for bronze in fuel oil and raw water environments
- loss of material and flow blockage for carbon steel in fuel oil, raw water, and wetted gas environments
- loss of material, cracking and flow blockage for stainless steel in raw water and fuel oil environments
- cracking, loss of material, and flow blockage brass in fuel oil and raw water

environments

- cracking and loss of material for brass alloys in fuel oil environment
- cracking, loss of material and flow blockage for chrome-plated brass in a raw water environment
- changes in material properties for neoprene and rubber in the fuel oil environment
- flow blockage and loss of material for black steel in the raw water environment
- cracking, loss of material and flow blockage for copper in the raw water environment

The applicant also identified fire barrier components such as fire walls, fire penetration seals, fire doors, and fire wraps as within the scope of license renewal and subject to AMR. The applicant considered these components with their respective structures under the Hazard Barriers and Elastomers structural commodity group in LRA Sections 2.4 and 3.5. These components were reviewed by the staff and are addressed in Section 3.5 of this SER.

3.3.7.1.2 Aging Management Programs

The applicant credits the following AMPs to manage aging effects of the fire protection system:

- Fire Protection Activities
- Outdoor, Buried, and Submerged Component Inspection
- Oil Quality Testing

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components in this system will be adequately managed by these aging management programs such that there is reasonable assurance that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.3.7.2 Staff Evaluation

The applicant described its AMR of the fire protection system for license renewal in Section 2.3.3.7 and Table 3.3-7. The staff reviewed this section and table to determine whether the applicant has demonstrated that the effects of aging on the fire protection system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.7.2.1 Aging Effects

During a teleconference on July 15, 2002, the staff requested the applicant to explain the exclusion of aging effects for carbon steel in the outdoor environment. The applicant submitted a supplement RAI response to RAI 3.3-4 to address this issue. The applicant states that the exhaust piping for the fire protection diesel-driven pump is routed outdoors to safely emit the exhaust gases outside of the building. The pressure boundary integrity of the exhaust piping is critical for the indoor piping; however, once the exhaust piping penetrates the roof slabs, the pressure boundary integrity of the exhaust piping is no longer critical. Throughwall corrosion of the outdoor exhaust piping will not impact the operability or availability of the fire protection diesel-driven pump since exhaust gas flow through pipe-wall breaches is still safely emitted outside the buildings.

In a letter dated February 6, 2002, the staff issued RAI 3.3-11 to request the applicant to provide information supporting the exclusion of aging effects for bronze in the outdoor environment. The applicant responded to this RAI by a letter dated May 6, 2002. In this letter the applicant stated that the aging management review determined that there are no aging effects for bronze in an outdoor environment because of an evaluation in Electrical Power Research Institute (EPRI) document 1003056, “Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools”, Rev. 3. This evaluation concludes that copper alloys are resistant to general corrosion in a gas environment, even in the presence of oxygen and moisture. The applicant equated the gas environment from the EPRI document to the wetted gas environment and stated that the wetted gas environment is, therefore, similar to the outdoor environment. The applicant further states that the atmospheric conditions at PBAPS do not contain high levels of contaminants that would result in an aggressive corrosive environment. Given that the outdoor environment will contain agents such as sulfates, nitrates, sulfur dioxide, sulfuric acid, and lead that could contribute to the corrosion of bronze, applicant needs to provide a more quantitative response regarding the levels of contamination at the site. PBAPS is located near areas that are in “nonattainment status” with respect to air quality, which means that the air quality does not meet minimum national air quality standards. In addition, the applicant alludes to the fact that the outdoor environment is corrosive by stating that the atmospheric conditions are not an "aggressive corrosive environment." That wording suggests that the environment is, although not aggressively corrosive, corrosive nonetheless, and therefore capable of inducing aging effects. During a meeting on July 18, 2002, the staff communicated these concerns to the applicant. The applicant noted the staff’s concerns and committed to providing a response to facilitate the staff’s completion of this SER. By letter dated July 29, 2002, the applicant supplemented RAI 3.3-11, informing the staff that the bronze valves in question are 2.5-inch angle valves used for fire hose connections. The valves are normally closed and capped. Although the outer material of these valves is exposed to the outdoor environment, the bronze material inside the valves is exposed to raw water and subject to aging management. Fire protection activities include visual inspection of valves to detect loss of material, cracking and flow blockage. Therefore, the component integrity of these valves is provided via these fire protection activities.

The staff finds that the applicant’s responses adequately address RAI 3.3-4 and RAI 3.3-11.

The aging effects of the SSCs in the fire protection system exposed to the environments that the applicant identified in the LRA are consistent with industry experience. The staff finds that the aging effects identified are appropriate.

3.3.7.2.2 Aging Management Programs

Section 2.3.3.7 and Table 3.3-7 of the LRA state that the following aging management programs are credited for managing the aging effects in the fire protection system:

- Fire Protection Activities
- Outdoor, Buried, and Submerged Component Inspection
- Oil Quality Testing

The Fire Protection Activities, Outdoor, the Buried, and Submerged Component Inspection, and the Oil Quality Inspection are credited with managing the aging effects of several components in various different structures and systems and are, therefore, considered common aging management programs. The staff review of the common aging management programs is in Section 3.0 of this SER.

The staff evaluated the aging management programs identified in Section 3.0.3.16 and found them to be acceptable for managing the aging effects identified for the fire protection system.

3.3.7.2.3 Conclusions

The staff has reviewed the information in Sections 2.3.3.7 and 3.3.7 of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the fire protection system will be adequately managed so that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.8 Control Room Ventilation System

3.3.8.1 Technical Information in the Application

The aging management review results for the control room ventilation system are presented in Table 3.3-8 of the LRA.

Section 2.3.3.8 of the LRA states that the control room ventilation system is a safety-related system that is common to Units 2 and 3. The system consists of several subsystems: the control room fresh air supply, control room emergency ventilation filter, control room air conditioning ventilation supply, and control room return air systems.

The system ensures the habitability of the control room even under design basis events. The fresh air portion of the system is operable during the loss of offsite power. The fresh air intake is filtered when control room emergency ventilation is initiated to prevent iodine and particulate contamination of the control room air.

The system consists of normal and emergency ventilation supply fans, air conditioning supply and return fans, filters, heating coils and cooling coils, refrigerant water chillers, chilled water pumps, dampers, ductwork, instrumentation, and controls.

The control room fresh air supply system consists of two 100%-capacity, redundant supply fans, a roll filter, and a preheat coil. The system is supplied with outside air from the outside air intake plenum.

The control room emergency ventilation filter system is a safety-related system which consists of two 100%-capacity filter units and redundant supply fans. Each filter unit consists of a charcoal filter and two banks of high-efficiency particulate air (HEPA) filters, one upstream and the other downstream of the charcoal filter.

3.3.8.1.1 Aging Effects

The control room ventilation system contains castings and forgings (valve bodies), piping (pipe and tubing), pipe specialities (flow elements), and sheet metal (ducting, damper enclosures, plenums, and fan enclosures) constructed from stainless steel, brass, carbon steel, and copper. These components are exposed to a sheltered environment. The applicant found no aging effects requiring management for these components.

The control room ventilation system contains elastomers (fan flex connections and filter plenum access door seals) constructed from fiberglass-impregnated neoprene, sponge, neoprene, and rubber and exposed to sheltered and ventilation environment. The applicant identified change in material properties as the aging effect.

The control room ventilation system contains castings and forgings (valve bodies), piping (pipe and tubing), piping specialities (flow elements), sheet metal (plenums, fan enclosures, louvers, ducting, and damper enclosures) constructed from stainless steel, brass, copper, and galvanized steel and exposed to a ventilation atmosphere. The applicant identified no aging effects requiring management for this combination of materials and environment.

3.3.8.1.2 Aging Management Programs

The following AMP is utilized to manage aging effects on the control room ventilation system:

- the ventilation inspection and testing activities

A description of the aging management program (activities) is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the control room ventilation system will be adequately managed by the aging management program such that there is reasonable assurance that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.3.8.2 Staff Evaluation

The staff reviewed Section 2.3.3.8 and Table 3.3.8 of the application to determine whether the applicant has demonstrated that the effects of aging on these component groups will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.8.2.1 Aging Effects

The control room ventilation system contains castings and forgings (valve bodies), piping (pipe and tubing), pipe specialities (flow elements), and sheet metal (ducting, damper enclosures, plenums, and fan enclosures) constructed from stainless steel, brass, carbon steel, and copper. These components are exposed to a sheltered environment. The applicant found no aging effects requiring management for these components. The staff agrees that for this materials/environment combination, there are no aging effects requiring management, as demonstrated by industry experience.

The control room ventilation system contains elastomers (fan flex connections and filter plenum access door seals) constructed from fiberglass-impregnated neoprene, sponge, neoprene, and rubber and exposed to sheltered and ventilation environments. The applicant identified change in material properties as the aging effect. The staff agrees that based on industry experience the applicant has identified the appropriate aging effects for these combinations of materials and environments.

The control room ventilation system contains castings and forgings (valve bodies), piping (pipe and tubing), piping specialities (flow elements), sheet metal (plenums, fan enclosures, louvers, ducting, and damper enclosures) constructed from stainless steel, brass, copper, and galvanized steel. These components are exposed to a ventilation atmosphere. The applicant identified no aging effects requiring management for this combination of materials and environment. The staff agrees that for is materials/environment combination, there are no aging effects requiring management, as demonstrated by industry experience.

The aging effects of the SSCs in the control room ventilation system exposed to the environments the applicant identified in the LRA are consistent with industry experience. The staff finds that the aging effects identified are appropriate.

3.3.8.2.2 Aging Management Programs

The applicant identified the following aging management program that will manage the aging effects of the control room ventilation system:

- the ventilation system inspection and testing activities

The ventilation system inspection and testing activities are reviewed in Section 3.0.3.12 of this SER. The staff agrees that the applicant has identified the appropriate aging effects for these combinations of materials and environments and that the ventilation inspection and testing activities will adequately manage the effects of aging for the extended period of operation.

3.3.8.3 Conclusions

The staff has reviewed the information on aging effects and aging management activities for the materials and environments of the control room ventilation system, and the staff concludes that the applicant has demonstrated that aging effects associated with the subject components will be adequately managed so there is reasonable assurance that the subject system will perform its intended functions in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.9 Battery and Emergency Switchgear Ventilation System

3.3.9.1 Technical Information in the Application

The aging management review results for the battery and emergency switchgear ventilation system is in Table 3.3-9 of the LRA.

Section 2.3.3.9 of the LRA states that the battery and emergency switchgear ventilation system consists of a common air supply system and separate exhaust systems. Outdoor air is filtered, conditioned by heating coils when required, and discharged by one of the two supply fans to the emergency switchgear and battery rooms of Units 2 and 3. One of the two emergency switchgear room return air fans is controlled by an air-operated damper and exhausts air to atmosphere at the radwaste building roof or back to the suction of the supply fan. One of the two battery room exhaust fans discharges exhaust air from the battery rooms to atmosphere at the radwaste building roof. Loss of duct pressure automatically starts standby fans and sounds an alarm in the main control room.

The ventilation system is normally in operation and continues to operate during accident conditions, including the loss of offsite power. All system controls are from a local panel. Redundant fans are provided for reliable system operation.

3.3.9.1.1 Aging Effects

In Table 3.3-9 of the LRA, the applicant identifies the components of the battery and emergency switchgear ventilation system. The system contains castings and forgings (valve bodies), piping (tubing), sheet metal (ducting, plenums, damper enclosures, and fan enclosures), constructed from stainless steel, galvanized steel mesh, and carbon steel and exposed to a sheltered environment. The applicant found no aging effects requiring management for these components in a sheltered environment.

The battery and emergency switchgear ventilation system also contains castings and forgings (valve bodies), piping (tubing), sheet metal (exhaust hoods, fan enclosures, ducting, plenums, damper enclosures, and louvers), constructed from stainless steel, galvanized steel mesh, galvanized steel with galvanized casing, and carbon steel. These components are exposed to a ventilation atmosphere. The applicant found no aging effects requiring management for these components in a ventilation atmosphere.

The battery and emergency switchgear ventilation system contains elastomers (fan flex connections) constructed from fiberglass-impregnated neoprene and exposed to both a sheltered and a ventilation atmosphere. The applicant identified change in material properties as an aging effect requiring management.

The components of this system are fabricated from carbon steel, stainless steel, and galvanized steel.

3.3.9.1.2 Aging Management Programs

The LRA identifies the following aging management program that will manage the aging effects of the battery and emergency switchgear ventilation system:

- ventilation system inspection and testing activities

Appendix B of the LRA contains a detailed description of the aging management program. The LRA cites this program for managing aging effects for the fan flex connections of the battery and emergency switchgear ventilation system.

3.3.9.2 Staff Evaluation

The staff reviewed Section 2.3.3.9 and Table 3.3-9 of the application to determine whether the applicant has demonstrated that the effects of aging on these component groups will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.9.2.1 Aging Effects

The battery and emergency switchgear ventilation system contains castings and forgings (valve bodies), piping (tubing), sheet metal (ducting, plenums, damper enclosures, and fan enclosures) constructed from stainless steel, galvanized steel mesh, and carbon steel. These components are exposed to a sheltered environment. The applicant found no aging effects requiring management for these components. The staff agrees that, based on industry experience, there are no aging effects requiring management for these materials and environment combinations (see Section 3.3.0.6 of this SER).

The battery and emergency switchgear ventilation system contains castings and forgings (valve bodies), piping (tubing), sheet metal (exhaust hoods, fan enclosures, ducting, plenums, damper enclosures, and louvers), which are constructed from stainless steel, galvanized steel mesh, galvanized steel with galvanized casing, and carbon steel. These components are exposed to a ventilation atmosphere. The applicant found no aging effects requiring management for these components. The staff agrees that, based on industry experience, there are no aging effects requiring management for these materials and environment combinations.

The battery and emergency switchgear ventilation system contains elastomers (fan flex connections) constructed from fiberglass-impregnated neoprene and exposed to both a sheltered and a ventilation atmosphere. The applicant identified change in material properties as the aging effect.

The aging effects of the SSCs in the battery and emergency switchgear ventilation system exposed to the environments the applicant identified in the LRA are consistent with industry experience. The staff finds that the aging effects identified are appropriate.

3.3.9.2.2 Aging Management Programs

The battery and emergency switchgear ventilation system contains elastomers (fan flex connections) constructed from fiberglass-impregnated neoprene and exposed to both a sheltered and a ventilation atmosphere. The applicant identified change in material properties as the aging effect and credits the following activities for managing this aging effect during the period of extended operation:

- ventilation system inspection and testing activities

The ventilation system inspection and testing activities are reviewed in Section 3.0.3.12 of this SER. The staff agrees that the applicant has identified the appropriate aging effects for these combinations of materials and environments and that the ventilation inspection and testing activities will adequately manage the effects of aging for the extended period of operation.

3.3.9.3 Conclusions

The staff has reviewed the information on aging effects and aging management activities for the materials and environments of the battery and emergency switchgear ventilation system, and the staff concludes that the applicant has demonstrated that aging effects associated with the subject components will be adequately managed so there is reasonable assurance that the subject system will perform its intended functions in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.10 Diesel Generator Building Ventilation System

3.3.10.1 Technical Information in the Application

The aging management review results for the diesel generator building ventilation system are given in Table 3.3-10 of the LRA.

Section 2.3.3.10 of the LRA states that the diesel generator building ventilation system provides heating, cooling, and ventilation for personnel comfort, for the diesel generators and associated equipment, and for the ESW booster pumps. The system provides ventilation and cooling to the emergency diesel generator rooms during normal plant operation and following design basis events. It supplies heating as required during normal operating conditions. The system also provides ventilation, cooling, and heating as required to the Cardox and ESW booster pump room during normal plant operating conditions.

Each emergency diesel generator room is provided with ventilation air supply fans and an exhaust relief damper. Combustion air for the diesel engine is taken from the room. The ventilation systems are supplied with power from the diesels during the loss of offsite power.

The components in this system are fabricated from carbon steel, stainless steel, and galvanized steel. The ventilation system contains elastomers (fan flex connectors) made from fiberglass-impregnated neoprene.

3.3.10.1.1 Aging Effects

The diesel generator building ventilation system contains elastomers (fan flex connectors) made from fiberglass-impregnated neoprene and exposed to a sheltered and a ventilation atmosphere. The applicant identified change in mechanical properties as the applicable aging effect.

The diesel generator building ventilation system contains sheet metal (ducting, damper enclosures, and fan enclosures) constructed from carbon steel and galvanized steel and exposed to a sheltered environment. The applicant found no aging effects requiring management for these components.

3.3.10.2 Staff Evaluation

The staff reviewed Section 2.3.3.10 and Table 3.3-10 of the application to determine whether the applicant has demonstrated that the effects of aging on these component groups will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.10.2.1 Aging Effects

The diesel generator building ventilation system contains elastomers (fan flex connectors) made from fiberglass-impregnated neoprene and exposed to a sheltered and a ventilation atmosphere. The applicant identified change in mechanical properties as the applicable aging effect.

The diesel generator building ventilation system contains sheet metal (ducting, damper enclosures, and fan enclosures) constructed from carbon steel and galvanized steel and exposed to a sheltered environment. The applicant found no aging effects requiring management for these components. As discussed in Section 3.3.0.6 of this SER, the staff agrees that, based on industry experience, there are no aging effects requiring management for these combinations of materials and environments.

The aging effects of the SSCs in the diesel generator building ventilation system exposed to the environments the applicants identified in the LRA are consistent with industry experience. The staff finds that the aging effects identified are appropriate.

3.3.10.2.2 Aging Management Programs

The diesel generator building ventilation system contains sheet metal (fan enclosures, ducting, damper enclosures, and louvers) constructed from carbon steel and galvanized steel and exposed to a ventilation atmosphere. The applicant found no aging effects requiring management for these components. The staff agrees that there are no aging effects requiring management for these materials and environment combinations.

The diesel generator building ventilation system contains sheet metal (ducting, damper enclosures, and fan enclosures) constructed from carbon steel and galvanized steel and exposed to a sheltered environment. The applicant found no aging effects requiring management for these components. The staff agrees that, based on industry experience, there are no aging effects requiring management for these materials and environment combinations.

The diesel generator building ventilation system contains elastomers (fan flex connectors) made from fiberglass-impregnated neoprene and exposed to a sheltered and a ventilation atmosphere. The applicant identified change in mechanical properties as the applicable aging effect and credits the following program for managing the effects of aging during the extended period of operation:

- ventilation system inspection and testing activities

The ventilation system inspection and testing activities are reviewed in Section 3.0.3.12 of this SER. The staff agrees that the applicant has identified the appropriate aging effects for this combination of materials and environment and that the ventilation inspection and testing activities will adequately manage the effects of aging for the extended period of operation.

3.3.10.3 Conclusions

The staff has reviewed the information on aging effects and aging management activities for the materials and environments of the diesel generator building ventilation system. The staff concludes that the applicant has demonstrated that aging effects associated with the subject components will be adequately managed so there is reasonable assurance that the subject system will perform its intended functions in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.11 Pump Structure Ventilation System

3.3.11.1 Technical Information in the Application

The aging management review results for the pump structure ventilation system are given in Table 3.3-11 of the LRA.

Section 2.3.3.11 of the LRA states that each of the two seismic Class 1 emergency service water and high-pressure service water compartments housing the high-pressure service water pumps, emergency service water pumps, fire pumps, and service water screen wash pumps is provided with a ventilation supply and exhaust system in each of the two seismic Class 1 compartments. The pump structure ventilation system is supplied with standby power during the loss of offsite power. Redundant ventilation equipment is furnished in each compartment for uninterrupted service. Each pump room contains two safety-related 100%-capacity supply fans, two safety-related 100%-capacity exhaust fans, and one non-safety-related steam unit heater.

Each pump room has a missile-protected concrete air mixing box which contains an outdoor air damper and a return air damper. Air is exhausted to a missile-protected concrete exhaust plenum.

3.3.11.1.1 Aging Effects

The components of the pump structure ventilation system are described in Section 2.3.3.11 of the LRA. Table 3.3-11 of the LRA lists individual components of the system, including valve bodies, fan flex connections, piping, ducting, damper enclosures, louvers, and bird screens. The components are fabricated from brass, fiberglass-impregnated neoprene, copper, carbon steel, galvanized steel, or galvanized steel mesh. The components are exposed to a sheltered and ventilated enviroment, except the bird screens, which are exposed to an outdoor environment. The applicant identified change in material properties for fan flex connections constructed from fiberglass-impregnated neoprene and exposed to both a sheltered and a ventilation atmosphere as the only aging effect requiring management for the pump structure ventilation system.

3.3.11.1.2 Aging Management Programs

The LRA identifies the following aging management program that will manage the aging effects of the pump structure ventilation system:

- ventilation system inspection and testing activities

Appendix B of the LRA contains a detailed description of the aging management program. The LRA cites this program for managing aging effects for the fan flex connections of the pump structure ventilation system.

3.3.11.2 Staff Evaluation

The staff reviewed Section 2.3.3.11 and Table 3.3-11 of the application to determine whether the applicant has demonstrated that the effects of aging on these component groups will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.11.2.1 Aging Effects

The pump structure ventilation system contains castings and forgings (valve bodies), piping (tubing), sheet metal (ducting, louvers, damper enclosures, and fan enclosures) constructed from brass, copper, carbon steel, galvanized steel, or galvanized steel mesh. These components are exposed to a sheltered environment and ventilation atmosphere. The applicant found no aging effects requiring management for these components in the identified environment. The bird screens are made of galvanized screen mesh are exposed to an outdoor environment. No degradation mechanism requiring management has been identified for the bird screens. The staff agrees that, based on industry experience, for these materials and environment combinations, there are no identified aging effects requiring management.

The pump structure ventilation system contains elastomers (fan flex connections) constructed from fiberglass-impregnated neoprene and exposed to both a sheltered and a ventilation atmosphere. The applicant identified the change in material properties as the aging effect.

The aging effects of the pump structure ventilation system SSCs exposed to the environments the applicant identified in the LRA are consistent with industry experience. The staff finds that the aging effects identified are appropriate.

3.3.11.2.2 Aging Management Programs

The pump structure ventilation system contains elastomers (fan flex connections) constructed from fiberglass-impregnated neoprene and exposed to both a sheltered and a ventilation atmosphere. The applicant identified change in material properties as the aging effect and credits the following activities for managing this aging effect during the period of extended operation:

- ventilation system inspection and testing activities

The ventilation system inspection and testing activities are reviewed in Section 3.0.3.12 of this SER. The staff agrees that the applicant has identified the appropriate aging effects for this combination of materials and environment and that the ventilation inspection and testing activities will adequately manage the effects of aging for the extended period of operation.

3.3.11.3 Conclusions

The staff has reviewed the information on aging effects and aging management activities for the material/environments for the pump structure ventilation system, and the staff concludes that the applicant has demonstrated that aging effects associated with the subject components will be adequately managed so there is reasonable assurance that the subject system will perform its intended function in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.12 Safety-Grade Instrument Gas System

3.3.12.1 Technical Information in the Application

The safety-grade instrument gas (SGIG) system supplies pressurized nitrogen gas from the containment atmospheric dilution tank as a backup to normal instrument air. Spring-loaded check valves designed for zero leakage isolate the safety grade air supply from the non-safety-grade air supply. This system also acts as a backup pneumatic source to the containment atmospheric control purge and vent isolation valves, the torus to secondary containment vacuum breakers, and the containment dilution vent control valves following a loss of coolant accident (LOCA) coincident with a loss of instrument air.

The materials of construction of the SGIG system components are stainless steel and brass.

3.3.12.1.1 Aging Effects

The components of the SGIG system are described in Section 2.3.3.12 of the LRA as being within the scope of license renewal and subject to aging management review (AMR). Table 3.3-12 of the LRA lists the individual components of the system, including valve bodies, pipe and flexible hoses. The applicant identified no aging effects for stainless steel and brass in the sheltered and dry gas environments.

3.3.12.1.2 Aging Management Programs

Because the applicant did not identify any aging effects for this system, the applicant did not identify any aging management programs.

3.3.12.2 Staff Evaluation

The applicant described its AMR of the SGIG system for license renewal in Section 2.3.3.12 and Table 3.3-12. The staff reviewed this section and table to determine whether the applicant has demonstrated that the effects of aging on the SGIG system, if any, will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.12.2.1 Aging Effects

The applicant did not identify any aging effects for stainless steel and brass in sheltered or dry gas environments. This assessment is consistent with industry experience. Stainless steel and brass are resistant to age-related degradation such as loss of material and cracking under the dry, atmospherically controlled conditions that are of dry gas and sheltered environments.

The staff has reviewed the information in Sections 2.3.3.12 and 3.3.12 of the LRA. On the basis of this review, the staff finds that the applicant has demonstrated that no aging effects associated with the SGIG system require aging management. Therefore, there is reasonable assurance that aging effects will not inhibit this system from performing its intended functions in accordance with the CLB during the period of extended operation.

3.3.12.2.2 Aging Management Programs

The applicant did not credit any AMPs towards managing the aging effects of this system because no aging effects were identified. This assessment is consistent with industry practice. An aging management program is not required for passive SSCs that do not experience aging effects. The staff finds it acceptable for the applicant not to apply an aging management program to this system.

3.3.12.2.3 Conclusions

The staff has reviewed the information in Sections 2.3.3.12 and 3.3.12 of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that there are no aging effects for the SGIG system and that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.13 Backup Instrument Nitrogen to the Automatic Depressurization System

3.3.13.1 Technical Information in the Application

The backup instrument nitrogen to the automatic depressurization system (ADS) supplies safety-related pneumatic nitrogen to the ADS valves in the event that the instrument nitrogen system is unavailable or inoperable. The backup instrument nitrogen system consists of a split ring header with a seismic Category I bottle rack, three nitrogen bottles located in the reactor building, seismic Category I piping and valves, and an external nitrogen connection located outside the reactor building at the ground level. The split ring header supplies five ADS valves, three from one section of the header and two from the other section.

Locally mounted accumulators on each ADS valve provide a short-term nitrogen supply to the ADS and supply sufficient pneumatic pressure for two valve actuations at 70% of the drywell design pressure. The backup instrument nitrogen system also supports ADS in its emergency core cooling and residual heat removal capacity by providing a safety-related pneumatic supply capable of sustaining ADS operation for 100 days after a LOCA.

A long-term, backup, safety grade pneumatic nitrogen supply has been provided to selected safety relief valves. This pneumatic supply is provided to enable remote operation of the above valves for a period of 72 hours following a design basis fire areas that have been postulated to render the ADS valves available for only short-term operation. The source of the pneumatic nitrogen supply is the safety grade instrument gas that is tied into the liquid nitrogen tank that supplies the containment atmospheric dilution system.

The material of construction of the backup instrument nitrogen to the ADS is stainless steel.

3.3.13.1.1 Aging Effects

The components of the backup instrument nitrogen to ADS are described in Section 2.3.3.13 of the LRA as being within the scope of license renewal and subject to aging management review (AMR). Table 3.3-13 of the LRA lists the individual components of the system, including valve bodies, pipe, flexible hoses, flow element, and accumulators. The applicant identified no aging effects for stainless steel in the sheltered and dry gas environments.

3.3.13.1.2 Aging Management Programs

Because the applicant did not identify any aging effects for this system, the applicant did not identify any aging management programs.

3.3.13.2 Staff Evaluation

The applicant described its AMR of the backup instrument nitrogen to ADS for license renewal in Section 2.3.3.13 and Table 3.3-13. The staff reviewed this section and table to determine whether the applicant has demonstrated that the effects of aging on the backup instrument nitrogen to ADS will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.13.2.1 Aging Effects

The applicant did not identify any aging effects for stainless steel in sheltered or dry gas environments. This assessment is consistent with industry experience. Stainless steel is resistant to age-related degradation such as loss of material and cracking under the dry, atmospherically controlled conditions of dry gas and sheltered environments.

The staff has reviewed the information in Sections 2.3.3.13 and 3.3.13 of the LRA. On the basis of this review, the staff finds that the applicant has demonstrated that no aging effects associated with the backup instrument nitrogen to ADS require aging management. Therefore, there is reasonable assurance that aging effects will not inhibit this system from performing its intended functions in accordance with the CLB during the period of extended operation.

3.3.13.2.2 Aging Management Programs

The applicant did not credit any AMPs towards managing the aging effects of this system because no aging effects were identified. This assessment is consistent with industry practice. An aging management program is not required for passive SSCs that do not experience aging effects. The staff finds it acceptable for the applicant not to apply an aging management program to this system.

3.3.13.2.3 Conclusions

The staff has reviewed the information in Sections 2.3.3.13 and 3.3.13 of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated are no aging effects associated with the backup instrument nitrogen to ADS and that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.14 Emergency Cooling Water System

3.3.14.1 Technical Information in the Application

The technical information in the application is presented in Section 2.3.3.5 and Table 3.3-5 of the LRA. The emergency cooling water system provides a reliable backup source of cooling water to the emergency service water and high-pressure service water systems when the circulating water pump structure is isolated from the normal heat sink, Conowingo Pond. The source of water for the emergency cooling water system is the emergency cooling tower, which includes the reservoir.

The emergency cooling water system is designed to remove sensible and decay heat from the reactor primary and auxiliary systems so that the reactor can be shut down in the event of the unavailability of the normal heat sink. When the normal heat sink is lost, or when flooding occurs, sluice gates in the circulating water pump structure are closed. Water is provided through two gravity-fed lines from the emergency cooling tower basin into the circulating water pump structure. The emergency cooling water system pump in conjunction with the emergency cooling water system booster pump and high-pressure service water system pumps, supply heat exchangers with cooling water required to bring Units 2 and 3 to safe shutdown. Return water from the high-pressure service water system flows to the emergency cooling tower. Return water from the emergency cooling water system flows through one of the two emergency cooling water booster pumps and is pumped into the emergency cooling tower.

3.3.14.1.1 Aging Effects

The components of the emergency cooling water system are described in Section 2.3.3.14 of the submittal as being within the scope of license renewal and subject to aging management review. Table 3.3-14 of the LRA lists individual components of the system, including one ECW pump, two ESW booster pumps, three emergency cooling tower fans in an induced-draft three-cell cooling tower with an integral storage reservoir, and associated discharge and distribution piping. These components are made of carbon steel, cast iron, alloy steel, and stainless steel.

A description of the environments is provided in Table 3.3-14 of the LRA. The emergency cooling water system structures and components are exposed to the following environments:

- outdoor
- raw water
- buried
- sheltered

The following aging effects associated with the structures and components require aging management:

- cracking of stainless steel components in raw water environments
- cracking of stainless steel components in outdoor environments
- loss of material from carbon steel and stainless steel components in outdoor environments
- loss of material from carbon steel, lined carbon steel, cast iron, stainless steel, and alloy steel components in raw water environments
- flow blockage of carbon steel, lined carbon steel, cast iron, alloy steel, and stainless steel components in raw water environments
- loss of material from carbon steel in buried environments

3.3.14.1.2 Aging Management Programs

The following aging management activities manage aging effects for the emergency cooling water system structures and components:

- Outdoor, Buried, and Submerged Component Inspection Activities
- Generic Letter 89-13 Activities
- ISI Program
- Inservice Testing (IST) Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the emergency cooling water system will be adequately managed by these aging management programs so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.3.14.2 Staff Evaluation

The applicant described its AMR of the emergency cooling water system for license renewal in Section 2.3.3.14 and Table 3.3-14 of the LRA. The staff reviewed this section and table of the LRA to determine whether the applicant has demonstrated that the effects of aging on the emergency cooling water system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.14.2.1 Aging Effects

The emergency cooling water (ECW) system consists of one ECW pump, two ESW booster pumps, three emergency cooling tower fans, and associated discharge and distribution piping. These components are made of carbon steel, cast iron, alloy steel, and stainless steel.

Some valve bodies and piping made of stainless steel are exposed to an outdoor environment. The associated aging effects are identified in Table 3.3.14 of the LRA as loss of material and cracking. The staff believes that, under normal circumstances, stainless steel components exposed to an outdoor environment are not subject to loss of material. The applicant chose to be more conservative and identified loss of material as an aging effect and will manage it with appropriate aging management programs. The staff finds the aging effects identified acceptable.

Some components made of stainless steel are exposed to a raw water environment. The applicable aging effects are loss of material, cracking, and flow blockage.

Some carbon steel piping and cast iron pump casings are exposed to a raw water environment. The aging effects associated with exposure to this environment are loss of material and flow blockage.

Loss of material and flow blockage were identified as possible aging effects for alloy steel piping exposed to raw water.

The aging effects that result from the contact of emergency cooling water system structures and components with the environments identified in Table 3.3-14 are consistent with industry experience for these combinations of materials and environments. The staff finds that the aging effects identified above are appropriate for these combinations of materials and environments.

3.3.14.2.2 Aging Management Programs

Section 2.3.3.14 and Table 3.3-14 of the LRA credits the following aging management programs for managing the aging effects in the emergency cooling water system:

- Outdoor, Buried, and Submerged Component Inspection Activities
- Generic Letter 89-13 Activities
- ISI Program
- Inservice Testing (IST) Program

The Outdoor, Buried, and Submerged Component Inspection activities detect degradation due to loss of material or cracking of external surfaces for outdoor, buried, and submerged components. The program is implemented in accordance with PBAPS maintenance procedures and routine test procedures that provide instructions for visual inspections.

The GL 89-13 activities include both condition monitoring and mitigating activities for managing aging effects in the HPSW, ESW, and ECW systems and in other components using raw water as a cooling medium. System and component testing, visual inspections, UT, and biocide treatments are conducted to ensure that aging effects are managed such that system and component intended functions are maintained. The program manages loss of material, cracking, flow blockage, and heat transfer reduction aging effects in cooling water piping and components that are tested and inspected in accordance with the guidelines of NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-related Equipment."

The ISI program provides for visual inspection of selected surfaces of specific components and structural components, or alternatively their replacement/refurbishment during the performance of periodic surveillance and preventive maintenance activities. The program provides for condition monitoring of pressure-retaining piping and components in the scope of license renewal except for those components covered by the reactor pressure vessel and internals ISI program.

The IST program is implemented by a PBAPS specification and provides for inservice testing of Class 1, 2, and 3 pumps and valves in compliance with the ASME O&M Code. The program manages the aging effects of flow blockage in the ESW and ECW components exposed to raw water and heat transfer reduction for the torus water path through the RHR heat exchangers.

The Outdoor, Buried, and Submerged Component Inspection Activities Program, Generic Letter 89-13 Activities Program, and Inservice Testing (IST) Program are credited with managing the aging effects for several components in various different structures and systems and are, therefore, considered common aging management programs. A description of these programs is provided in Appendix B of the LRA. The staff review of the common aging management programs is in Section 3.0 of this SER.

3.3.14.3 Conclusions

The staff reviewed the information in Section 3.3.14 and Table 3.3-14 of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the emergency cooling water system structures and components will be adequately managed so that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.15 Condensate Storage System

3.3.15.1 Technical Information in the Application

The technical information regarding the condensate storage system is presented in Section 2.3.3.15 and Table 3.3-15 of the LRA. The condensate storage system is the preferred water supply for the high-pressure coolant injection system and the reactor core isolation cooling system. The system also provides plant system makeup, receives flow, and provides condensate for any continuous service needs. The condensate storage system is common to both units at Peach Bottom. Although the condensate storage system is non-safety-related, it supplies the high-pressure coolant injection and reactor core isolation cooling systems during fire safe shutdown and station blackout scenarios.

3.3.15.1.1 Aging Effects

The components of the condensate storage system are described in Section 2.3.3.15 of the LRA as being within the scope of license renewal and subject to aging management review. Table 3.3-15 of the LRA lists individual components of the system, including two 200,000-gallon-capacity carbon steel condensate storage tanks (one for each unit), two condensate transfer pumps, a condensate transfer system pump, and associated piping and valves necessary to complete required system functions. These components are made of carbon steel and stainless steel.

A description of the environments is provided in Table 3.3-15 of the LRA. The condensate storage system structures and components are exposed to the following environments:

- outdoor
- condensate storage water
- sheltered

The following aging effects associated with the structures and components require aging management:

- cracking of stainless steel components in condensate storage water
- cracking of stainless steel components in outdoor environments
- loss of material from carbon steel and stainless steel components in outdoor environments
- loss of material from carbon steel and stainless steel components in condensate storage water environments

3.3.15.1.2 Aging Management Programs

The following aging management activities manage aging effects for the condensate storage system structures and components:

- Outdoor, Buried, and Submerged Component Inspection Activities
- Condensate Storage Tank Chemistry

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the condensate storage system will be adequately managed by these aging management programs such that there is reasonable assurance that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.3.15.2 Staff Evaluation

The applicant described its AMR of the condensate storage system for license renewal in Section 2.3.3.15 and Table 3.3-15 of the LRA. The staff reviewed this section and table of the LRA to determine whether the applicant has demonstrated that the effects of aging on the condensate storage system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.15.2.1 Aging Effects

The condensate storage system consists of condensate storage tanks, condensate transfer pumps, and associated piping and valves. These components are made of carbon steel and stainless steel.

The condensate storage tanks are made of carbon steel. The internal surfaces of the tanks are exposed to a condensate storage water environment, while the exteriors are exposed to an outdoor environment. Loss of material is identified as the aging effect.

Some valve bodies, tank nozzles, and piping are made of stainless steel and are exposed to an outdoor environment. The associated aging effects are identified in Table 3.3.15 of the LRA as loss of material and cracking.

Some valve bodies and piping made of stainless steel are exposed to a condensate storage water environment. The aging effects associated with exposure to this environment are identified in Table 3.3.15 of the LRA as loss of material and cracking.

The aging effects that result from the exposure of condensate storage system structures and components to the environments listed in Table 3.3-15 are consistent with industry experience for these combinations of materials and environments. The staff finds that the aging effects listed are appropriate for these combinations of materials and environments.

3.3.15.2.2 Aging Management Programs

Section 2.3.3.15 and Table 3.3-15 of the LRA states that the following aging management programs are credited for managing the aging effects in the condensate storage system:

- Outdoor, Buried, and Submerged Component Inspection Activities
- Condensate Storage Tank Chemistry

The Outdoor, Buried, and Submerged Component Inspection activities detect degradation due to loss of material or cracking of external surfaces for outdoor, buried, and submerged components. The program is implemented in accordance with PBAPS maintenance procedures and routine test procedures that provide instructions for visual inspections.

The Outdoor, Buried, and Submerged Component Inspection program and Condensate Storage Tank Chemistry Program are credited with managing the aging effects of several components in various different structures and systems and are, therefore, considered common aging management programs. The staff review of the common aging management programs is in Section 3.0 of this SER.

3.3.15.3 Conclusions

The staff reviewed the information in Section 3.3.15 and Table 3.3-15 of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the condensate storage system structures and components will be adequately managed so that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.16 Emergency Diesel Generator

3.3.16.1 Technical Information in the Application

The four emergency diesel generators (EDGs) provide Class 1E electrical power to the emergency buses during a loss of offsite power (LOOP) or a LOCA coincident with a LOOP. The EDGs also support onsite power transfer from one offsite safeguard source to another by providing a parallel source of AC power to emergency buses during the transfer operation. Each EDG set consists of a diesel engine, a generator, and auxiliary systems (starting air, fuel oil, jacket cooling, air cooling, and lubricating oil). Each EDG is connected to one 4kV Class 1E emergency bus per unit and is automatically started on LOOP, low reactor water level, or high drywell pressure signals.

The components of the emergency diesel generators are described in Section 2.3.3.16 of the LRA as being within the scope of license renewal and subject to aging management review (AMR). The materials of construction within the EDGs are cast iron, carbon steel, bronze, copper alloys, aluminum, aluminum alloys, stainless steel, neoprene and rubber, brass, and brass alloys. Table 3.3-16 of the LRA lists the individual components of the system, including valve bodies, strainer screens, pump casings, pipe, tubing, fittings, strainer bodies, restricting orifices, flexible hoses, fuel oil day tanks, fuel oil storage tanks, lubricating oil tanks, EDG jacket coolant coolers, EDG air cooling coolers, EDG lube oil coolers, expansion joints, thermowells, thermowell caps, drain traps, the expansion tank, air receivers, and silencers.

3.3.16.1.1 Aging Effects

The applicant identified no aging effects for cast iron, carbon steel, bronze, copper alloys, aluminum, aluminum alloys, stainless steel, neoprene and rubber, brass and brass alloys in the sheltered environment and no aging effects for carbon steel components in the outdoor, wetted gas, and lubricating oil environments and stainless steel components in the outdoor environment. The applicant identified the following aging effects for various combinations of component materials and internal and external environments.

- cracking, loss of material, reduction in heat transfer, and flow blockage for cast iron in closed cooling water, lubricating and fuel oil, wetted gas, raw water environments
- cracking and loss of material for aluminum in closed cooling water and lubricating and fuel oil environments
- cracking and loss of material for aluminum alloys in the lubricating and fuel oil environment
- loss of material for bronze in closed cooling water and lubricating and fuel oil environments
- cracking, loss of material, and heat transfer reduction for carbon steel in closed cooling water, lubricating and fuel oil, buried, and wetted gas environments
- cracking and loss of material for stainless steel in closed cooling water, lubricating and fuel oil, and wetted gas environments
- cracking and loss of material for brass in closed cooling water and lubricating and fuel oil environments
- cracking and loss of material for brass alloys in the lubricating and fuel oil environment
- changes in material properties for neoprene and rubber in closed cooling water and lubricating and fuel oil environments
- change in material properties for neoprene in the wetted gas environment
- cracking and loss of material for copper and copper alloys in the lubricating and fuel oil environment
- cracking, loss of material, heat transfer reduction and flow blockage for admiralty in closed cooling water, lubricating oil, and raw water environments
- cracking, loss of material, heat transfer reduction, and flow blockage for muntz metal in closed cooling water, lubricating oil, and raw water

3.3.16.1.2 Aging Management Programs

The applicant credits the following AMPs to manage aging effects of the emergency diesel generators:

- Closed Cooling Water (CCW) Chemistry
- Outdoor, Buried, and Submerged Component Inspection
- Oil Quality Testing
- Emergency Diesel Generator Inspection
- GL 89-13 Activities

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components in this system will be adequately managed by these aging management programs so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.3.16.2 Staff Evaluation

The applicant described its AMR of the emergency diesel generators for license renewal in Section 2.3.3.16 and Table 3.3-16. The staff reviewed this section and table to determine whether the applicant has demonstrated that the effects of aging on the emergency diesel generators will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.16.2.1 Aging Effects

By letter dated February 6, 2002, the staff requested additional information per RAI 3.3-4 to clarify inconsistencies in the identification of cracking or loss of material as aging effects for several carbon steel components within the system. By letter dated May 6, 2002, the applicant acknowledged that cracking due to vibration is an applicable aging effect for components mounted on or near the diesel engines as described in NRC Information Notice 89-07 and 98-43. The applicant identified these susceptible components in the LRA. In addition, the applicant informed the staff that the carbon steel strainer screen in the wetted gas environment is not susceptible to loss of material because the screen is in the diesel starting air piping that accumulates moisture upstream of the strainer. This moisture is removed daily when the system is blown down; therefore, the strainer is not subject to significant wetting.

The applicant's original RAI response did not address the exclusion of loss of material and/or cracking as aging effects for carbon steel in the outdoor environment. During a teleconference on July 15, 2002, the staff requested the applicant to address this issue. The applicant explained that the carbon steel component in question is exhaust piping for the EDGs. This piping is routed through building penetrations that vent to the atmosphere. The staff further inquired about the environment of the indoor routings because the application did not appear to address the indoor piping. At that time, the applicant was unable to confirm whether the indoor piping was included in the LRA. Subsequent to the teleconference, the applicant submitted a supplement to RAI 3.3-4 stating that the exhaust piping for the EDGs is routed outdoors to safely emit the exhaust gases outside of the buildings. The pressure boundary integrity of the exhaust piping is critical for the indoor piping; however, once the exhaust piping penetrates the roof slabs, the pressure boundary integrity of the exhaust piping is no longer critical. Throughwall corrosion of the outdoor exhaust piping will not impact the operability or availability of the EDGs since exhaust gas flow through pipe wall breaches is still safely emitted outside the buildings. Furthermore, the applicant stated that the indoor carbon steel exhaust piping had been inadvertently omitted from LRA Table 3.3-16. Specifically, the applicant stated that the indoor carbon steel exhaust piping is exposed to an internal environment of wetted gas and susceptible to loss of material. The applicant credits the Emergency Diesel Generator Inspection Activities for managing this aging effect.

The aging effects of the SSCs in the emergency diesel generators exposed to the environments the applicant identified in the LRA are consistent with industry experience. The staff finds that the aging effects identified are appropriate.

With respect to cracking of carbon steel components, the applicant's RAI response was consistent with industry experience. Because the applicant identified loss of material as an aging effect for carbon steel in the wetted gas environment and provided additional information clarifying the exclusion of aging effects for the carbon steel components specified in the RAI, the staff finds the applicant's response adequately addresses RAI 3.3-4..

3.3.16.2.2 Aging Management Programs

Section 2.3.3.16 and Table 3.3-16 of the LRA credit the following aging management programs for managing the aging effects in the emergency diesel generators:

- Closed Cooling Water (CCW) Chemistry
- Outdoor, Buried, and Submerged Component Inspection
- Oil Quality Testing
- Emergency Diesel Generator Inspection
- GL 89-13 Activities

CCW Chemistry, Outdoor, Buried, and Submerged Component Inspection, Oil Quality Inspection, and GL 89-13 Activities are credited with managing the aging effects of several components in various different structures and systems and are, therefore, considered common aging management programs. The staff review of the common aging management programs is in Section 3.0 of this SER. The staff evaluation of the EDG inspection AMP follows.

Emergency Diesel Generator Inspection AMP

The applicant described the emergency diesel generator (EDG) inspection AMP in Section B.2.4 of Appendix B to the LRA. The applicant credits this program with managing the effects of aging of EDG equipment that is within the scope of license renewal. The staff has reviewed Section B.2.4 of the LRA to determine whether the applicant has demonstrated that the effects of aging will be adequately managed by the program during the extended period of operation as required by 10 CFR 54.21(a)(3).

The EDG inspection activities provide for condition monitoring of in-scope EDG equipment that is exposed to a gaseous, closed cooling water or lubricating oil or fuel oil environment. Loss of material in the starting air system air receivers is mitigated by daily removal of any accumulation of condensate. Loss of material and cracking in lubricating oil and fuel oil systems is mitigated by periodic oil quality inspections. Visual inspections for change in material properties of flexible hoses in the starting air system and the cooling water system are performed in accordance with a plant procedure for periodic EDG maintenance. This procedure will be enhanced to require inspections of the lubricating oil and fuel oil system flexible hoses for change in material properties. The aging management of the loss of material in the EDG exhaust silencer will be enhanced by periodic disassembly, cleaning, and inspection of an automatic drain trap to ensure its functionality in preventing condensation buildup.

The staff's evaluation of the EDG inspection program focused on how the program manages the aging effect through the effective incorporation of the following 10 elements: program scope, preventive or mitigative actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled quality assurance program pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components that are subject to an aging management review. The applicant's quality assurance program is evaluated separately in Section 3.0.4 of this SER. This program satisfies the elements of corrective actions, confirmation process, and administrative controls. The remaining seven elements are discussed below.

Program Scope: The EDG inspection activities manage the aging effects of loss of material cracking, and change in material properties by—

- mitigating actions which ensure periodic removal of moisture from the starting air system air receivers
- periodic inspections of the EDG lubricating oil and fuel oil systems for loss of material and cracking
- periodic inspections of flexible hoses in the starting air and cooling water systems for change in material properties

The scope of the EDG inspection activities will be enhanced to—

- perform periodic inspections of EDG lubricating oil and fuel oil system flexible hoses for change in material properties
- periodically disassemble, clean, and inspect the EDG exhaust silencer drain trap to prevent condensation buildup and the resulting loss of material of the exhaust and silencer

The staff finds the program scope adequate and acceptable because the inspections cover all EDG components susceptible to aging effects under the scope of license renewal.

Preventive Actions: The EDG inspection activities provide mitigation methods to manage loss of material in the starting air system air receivers and the EDG exhaust silencer by ensuring periodic removal of moisture. The remaining EDG inspection activities provide inspection methods to identify aging effects, and thus have no preventive or mitigative attributes. The staff did not identify the need for additional preventative actions, and finds the preventive actions proposed by the applicant appropriate and acceptable.

Parameters Monitored or Inspected: The existing EDG inspection activities provide for—

- blowing down the EDG starting air system air receivers until no more moisture is present in the drain line
- performing visual inspections of the lubricating oil and fuel oil systems for the EDG fuel oil storage tanks for loss of material
- performing visual inspections of the starting air and cooling water system flexible hoses for change in material properties

EDG inspection activities will be enhanced to include—

- performance of visual inspections of the lubricating oil and fuel oil system flexible hoses for change in material properties
- periodic disassembly, cleaning, and inspection of the EDG exhaust silencer drain trap to ensure it is operating properly

The staff finds that the parameters monitored will permit timely detection of the aging effects and are, therefore, acceptable.

Detection of Aging Effects: The starting air system air receiver inspections and the periodic exhaust silencer automatic drain trap preventive maintenance activities mitigate potential aging effects. Visual inspections of the EDG fuel oil day tanks and the EDG lubricating and fuel oil system components and visual and UT inspections of the EDG fuel oil storage tanks are performed to assess loss of material and cracking aging effects. Visual inspection of flexible hoses provides for detection of change in material properties by observation of swelling or cracking. Peach Bottom procedures for EDG maintenance contain requirements for visual examinations of starting air and cooling water system flexible hoses. This procedure will be enhanced to include inspections of lubricating and fuel oil system flexible hoses. The staff finds that the proposed inspection techniques are consistent with industry practice and experience, are capable of detecting the relevant aging effects, and are, therefore, acceptable.

Monitoring and Trending: Existing EDG inspection activities provide the following monitoring and trending activities:

- Daily starting air system receiver inspections mitigate aging and require no monitoring or trending.
- EDG lubricating and fuel oil system examinations for loss of material and cracking are performed every 2 years for engine-mounted components and every 10 years for the EDG fuel oil storage tank and day tank interiors.
- Starting air and cooling water system flexible hose examinations for a change in material properties are conducted every 2 years.

Enhancements to EDG inspection activities will provide the following monitoring and trending activities:

- Examinations of the EDG lubricating and fuel oil system flexible hoses for a change in material properties will be conducted every 2 years.
- The periodic preventive maintenance of the EDG exhaust silencer automatic drain trap will mitigate aging and requires no monitoring or trending.

The staff finds this aspect of the inspection activities acceptable in that the monitoring and trending provides advance warning to permit corrective action before there is loss of intended function.

Acceptance Criteria: The EDG starting air system air receiver inspection contains the requirement to blow down the air receiver until there is no moisture in its drain line. Examinations for loss of material, visible cracking, and change in material properties aging effects are conducted in accordance with approved Peach Bottom procedures. Degraded components are repaired or replaced as required. The EDG exhaust silencer automatic drain trap preventive maintenance will ensure the trap is left in good working order. The staff finds the acceptance criteria acceptable because they are consistent with industry experience and practice.

Operating Experience: The overall effectiveness of the EDG inspection activities is supported by Peach Bottom’s operating experience with the starting air, engine exhaust, cooling water, lubricating oil, and fuel oil systems. Minor leakage events in the starting air, engine exhaust, cooling water, lubricating oil, and fuel oil systems have been detected and corrected in a timely manner. Due to numerous small leaks, portions of the EDG exhaust piping have been replaced. Water and sediment have been observed during the fuel oil storage tank inspections. During the 1995-1996 fuel oil storage tank inspections the lowest tank shell UT reading was 0.375 inch, which is equal to the original specified thickness for the shell. No age-related failures have been observed in EDG system flexible hoses. There have been no starting air, engine exhaust, cooling water or lubricating or fuel oil system age-related components failures resulting in a loss of function in the EDG.

By letter dated April 29, 2002, after a teleconference with the staff on April 3, 2002, the applicant provided additional information in response to RAI B.2.4-1 regarding the operating experience cited in LRA Section B.2.4 "Emergency Diesel Generator Inspection Activities." The applicant clarified that the AMR included a review of both industry and plant operating experience. In addition, the applicant stated that NRC generic communications, such as NRC Information Notice 89-07, were considered in the AMR and incorporated into the EDG inspection activities.

The staff finds that the applicant's response adequately addresses RAI B.2.4-1 with respect to operating experience.

The staff finds that the applicant's operating experience has demonstrated that the inspection program for EDGs has effectively maintained the integrity of the EDG components and will be effective during the license renewal period as well.

The staff reviewed the UFSAR Supplement in Section A.2.4 of the LRA and found that the description of the applicant's summary description activities discussed above is consistent with Section B.2.4 of the LRA and is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

The staff has reviewed the information in Section B.2.4 of the LRA. On the basis of its review, as described above, the staff concludes that the applicant has demonstrated that there is reasonable assurance that the program will adequately manage aging effects associated with the systems and components for the period of extended operation as required by 10 CFR54.21(a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above, as required by 10 CFR 54.21(d).

3.3.16.2.3 Conclusions

The staff has reviewed the information in Sections 2.3.3.16 and 3.3.16 of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the emergency diesel generators will be adequately managed so that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.17 Suppression Pool Temperature Monitoring System

3.3.17.1 Technical Information in the Application

The suppression pool temperature monitoring system (SPOTMOS) provides a control room indication of the individual and average bulk torus water temperature to ensure torus water is maintained within specified temperature limits. The system also provides indication of torus water temperature at the remote shutdown panel and the high-pressure coolant injection alternative control station when the control room is inaccessible.

The components of the SPOTMOS are described in Section 2.3.3.17 of the LRA as being within the scope of license renewal and subject to aging management review (AMR). The material of construction SPOTMOS components is stainless steel. Table 3.3-17 of the LRA lists the individual components of the system, including the penetration sleeves.

3.3.17.1.1 Aging Effects

The applicant identified no aging effects for stainless steel in the sheltered environment. The applicant identified loss of material for stainless steel in torus water.

3.3.17.1.2 Aging Management Programs

The applicant credits the Primary Containment ISI program to manage aging effects of the SPOTMOS. This aging management program is described in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of this system will be adequately managed by this aging management program so that there is reasonable assurance that the intended function will be maintained consistent with the CLB during the period of extended operation.

3.3.17.2 Staff Evaluation

The applicant described its AMR of the SPOTMOS for license renewal in Section 2.3.3.17 and Table 3.3-17. The staff reviewed this section and table to determine whether the applicant has demonstrated that the effects of aging on the SPOTMOS will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.17.2.1 Aging Effects

By letter dated February 6, 2002, the staff requested additional information per RAI 3.3-5 to justify the exclusion of cracking as an aging effect for stainless steel in torus water. By letter dated May 6, 2002, the applicant informed the staff that the stainless steel component in question is exposed to torus water that is less than 95 °F. NUREG-0313, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping," considers stainless steel susceptible to significant cracking only at operating temperatures above 200 °F. Because the torus water operating temperature is below this limit, the applicant did not identify cracking as an aging effect.

The staff finds that the applicant’s response adequately addresses RAI 3.3-5.

The aging effects of the SPOTMOS SSCs exposed to the environments the applicant identified in the LRA are consistent with industry experience. The staff finds that the aging effects identified are appropriate.

3.3.17.2.2 Aging Management Programs

Section 2.3.3.17 and Table 3.3-17 of the LRA state that the Primary Containment ISI program is credited for managing aging effects of the SPOTMOS. The Primary Containment ISI program is credited with managing the aging effects of several components in several different structures and systems and is, therefore, considered a common aging management program. The staff review of the common aging management programs is in Section 3.0 of this SER.

The staff evaluated the aging management program identified in Sections 2.3.3.17 and 3.3.17 and found it to be acceptable for managing the aging effects identified for the SPOTMOS.

3.3.17.2.3 Conclusions

The staff has reviewed the information in Sections 2.3.3.17 and 3.3.17 of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the SPOTMOS will be adequately managed so that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.18 Cranes and Hoists

3.3.18.1 Technical Information in the Application

The reactor building cranes and cranes such as the four emergency diesel generator building cranes and hoists are designed and analyzed to maintain their structural integrity and perform tasks without preventing the SSCs from performing their intended safety functions. The reactor building crane is designed to lift and transport spent fuel casks such that no credible postulated failure of any crane component will result in the dropping of a cask. The reactor building cranes also support single-failure-proof criteria for lifting heavy loads over fuel in the reactor pressure vessel or over the spent fuel pool.

The components of the cranes and hoists are described in Section 2.3.3.18 of the LRA as being within the scope of license renewal and subject to aging management review (AMR). The materials of construction of the cranes and hoists are stainless steel, carbon steel, and low-alloy steel. Table 3.3-18 of the LRA lists the individual components of the equipment, including structural members, rails, rail clips, rail bolts, and monorail flanges.

3.3.18.1.1 Aging Effects

The applicant identified no aging effects for stainless steel in the sheltered environment. The applicant identified carbon and low-alloy steel in outdoor and sheltered environments as susceptible to loss of material.

3.3.18.1.2 Aging Management Programs

The applicant credits Crane Inspection Activities to manage aging effects of the cranes and hoists. This aging management program is described in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of this system will be adequately managed by these aging management programs so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.3.18.2 Staff Evaluation

The applicant described its AMR of cranes and hoists for license renewal in Section 2.3.3.18 and Table 3.3-18. The staff reviewed this section and table to determine whether the applicant has demonstrated that the effects of aging on the cranes and hoists will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.18.2.1 Aging Effects

By letter dated February 6, 2002, the staff requested additional information per RAI 3.3-3 to justify the exclusion of fatigue and a corresponding TLAA evaluation relating to crane load cycles. By letter dated May 6, 2002, the applicant informed the staff that the LRA was amended to include load cycles for the reactor building overhead bridge cranes, turbine hall cranes, emergency diesel generator bridge cranes, and the circulating water pump structure gentry crane as a TLAA in Section 4.7.4

The staff finds that the applicant's response adequately addresses RAI 3.3-3.

The aging effect of the SSCs in cranes and hoists exposed to the environments the applicant identified in the LRA is consistent with industry experience. The staff finds that the aging effect identified is appropriate.

3.3.18.2.2 Aging Management Programs

Section 2.3.3.18 and Table 3.3-18 of the LRA credit the Crane Inspection Activities with managing aging effects of the cranes and hoists.

The applicant's crane inspection activities are described in Section B.1.14 of the LRA. This program is credited with managing the potential aging effect of loss of material for the passive components of the cranes and hoists. The staff has reviewed Section B.1.14 of the LRA to determine whether the applicant has demonstrated that the effects of aging will be adequately managed by the crane inspection activities during the extended period of operation as required by 10 CFR 54.21(a)(3).

The crane inspection activities at PBAPS consist of inspections that are relied upon to manage loss of material for passive components of cranes and hoists. These components are identified in Table 3.3-18 of the LRA. They include carbon steel and low-alloy steel structural support components in both outdoor and sheltered environments. The crane inspection activities comply with the requirements of ASME B30.2, B30.11, B30.16, and B30.17, and are implemented through a plant procedure.

The staff's evaluation of the crane inspection activities focused on how the program manages the aging effect through the effective incorporation of the following 10 elements: program scope, preventive or mitigative actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled quality assurance program pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components that are subject to an aging management review. The applicant's quality assurance program is evaluated separately in Section 3.0.4 of this SER. This program satisfies the elements of corrective actions, confirmation process, and administrative controls. The remaining seven elements are discussed below.

Program Scope: Crane inspection activities consist of inspections of the structural members, rails, and rail anchorage for the circulating water pump structure gantry crane located in an outdoor environment, and rails and monorails for the cranes and hoists located in a sheltered environment. The staff finds the program scope appropriate and acceptable because critical components of the cranes and hoists subject to aging management are covered by the inspection activities.

Preventive Actions: Crane inspection activities include inspections to identify component aging effects prior to loss of intended function. No preventive or mitigating attributes are associated with these activities, and the staff did not identify the need for any.

Parameters Monitored or Inspected: The LRA states that crane inspection activities verify structural integrity of crane and hoist elements required to maintain intended functions and comply with ASME B30.1, B30.11, B30.16, and B30.17. By letter dated April 29, 2002, the applicant provided an additional description of the crane inspection activities, noting those activities that are credited for license renewal. The activities include visual inspections for conditions such as corroded structural members, misalignment, flaking, sidewear of rails, loose tiedown bolts, and excessive wear or deformation of the monorail lower flange. The staff finds that visual inspections will detect the aging parameters stated above. The staff also finds that these parameters will adequately verify the structural integrity of the critical crane and hoist elements and are, therefore, acceptable.

Detection of Aging Effects: Crane inspection activities provide for inspections to identify deficiencies in components and degradation due to loss of material. The staff finds visual inspections to be an effective means of detecting the aging effect of concern and, therefore, finds visual inspections acceptable.

Monitoring and Trending: Crane inspection activities monitor inspection results from previously identified findings and for newly emerging conditions. The annual inspections provide for prediction of the onset of degradation and for timely implementation of corrective actions to prevent loss of intended function. The staff finds that the monitoring and trending of inspection results on an annual basis will identify degradation prior to structural failure and are, therefore, acceptable.

Acceptance Criteria: Crane inspection activities provide for engineering evaluation of inspection results to assess the ability of the crane or hoist to perform its intended function. The acceptance criterion is no unacceptable visual indication of loss of material due to corrosion or wear. The loss of material due to corrosion or wear of the critical crane and hoist elements can be identified based on visual inspections such that there is still a substantial margin to failure available. Therefore, the staff finds the acceptance criterion acceptable.

Operating Experience: No incidents of failure of passive crane and hoist components due to aging have occurred at PBAPS. Loss of material in crane rails and monorails has been detected and managed by the crane inspection activities. Therefore, the staff finds that there is reasonable assurance that the intended functions of crane and hoist passive components will be maintained during the period of extended operation.

The staff reviewed Section A.1.14 of the UFSAR Supplement (Appendix A of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 21(d).

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the crane and inspection activities will adequately manage the aging effects associated with the crane and hoist components for the period of extended operation as required by 10 CFR 54.21 (a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CRFR 54.21(d).

3.3.18.2.3 Conclusions

The staff has reviewed the information in Sections 2.3.3.18 and 3.3.18 of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effect associated with cranes and hoists will be adequately managed so that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.4 Aging Management of Steam and Power Conversion Systems

The applicant described its AMR of the steam and power conversion systems for license renewal in LRA Sections 2.3.4, "Steam and Power Conversion Systems," and 3.4, "Aging Management of Steam and Power Conversion Systems." The staff has reviewed this section and tables 3.4.1 thru 3.4-3 of the application to determine whether the applicant has provided adequate information to meet the requirements of 10 CFR 54.21(a)(3) for managing the aging effects of the steam and power conversion systems for license renewal.

The LRA identified three systems that will require aging management to meet the requirements of 10 CFR 54.21(a)(3) for management of aging effects. The three systems are the main steam system, main condenser, and feedwater system. The LRA included a summary of the results of the aging management review for these three systems. The results are listed in Tables 3.4-1 through 3.4-3 of the LRA. The tables provide the following information: (1) component groups, (2) component intended functions, (3) environments , (4) materials of construction, (5) aging effects, and (6) aging management activities that manage the identified aging effects.

Section 3.0 of the LRA identified seven environments that are applicable to the steam and power conversion systems:

- Reactor coolant: Reactor coolant system water is demineralized and maintained in accordance with stringent chemistry parameters to mitigate corrosion.

- Steam: Steam is produced in the reactor vessel from reactor-grade water and has extremely low levels of impurities. The systems that are pertinent to this evaluation are the reactor pressure vessel and internals, main steam, HPCI, and RCIC systems. The steam exists as a two-phase vapor, ranging from high-quality steam in the main steam system to low-quality steam in the HPCI and RCIC systems. The HPCI and RCIC steam lines normally see little to no steam flow because these systems operate infrequently.

- Torus-Grade Water: The torus-grade water quality is monitored periodically and maintained in accordance with station procedures that include recommendations from EPRI TR-103515, "BWR Water Chemistry Guidelines." Purity of the torus water is maintained by pumping the torus water through filters and demineralizers and by bleed and feed operations with the hotwell. Some carbon steel pipes in the torus pass through the surface of the torus water and are exposed to a water-gas interface. For lines equipped with vacuum breaker valves, the water-gas interface occurs at both the inside and outside diameter of the pipe. For other lines, a water-gas interface occurs only at the outside diameter because the inside of the pipe remains full of water.

- Raw Water: Raw water is untreated fresh water taken from Conowingo Pond, which is formed by the Susquehanna River. Raw water typically contains a dilute solution of mineral salt impurities, dissolved gases, and biological organisms. These dissolved gases (oxygen and carbon dioxide) are the prime corrosion-initiating agents. Water samples show pH variation from 7.00 to 7.55, chloride content of 9 to 18 ppm, and sulfate content from 1 to 46 ppm.

- Sheltered: 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 ^{0}F to 150 ^{0}F and a relative humidity ranging from 10% to 90%. The warmest room outside the drywell is the steam tunnel, with an average temperature of 150 ^{0}F (based on measured temperatures) and a maximum normal fluctuation to 165 ^{0}F. The drywell is inerted with nitrogen to render the containment atmosphere nonflammable by maintaining the oxygen content less than 4% oxygen. The drywell normal operating temperature ranges from 65 ^{0}F to 150 ^{0}F with a relative humidity from 10% to 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 external surface corrosion of metallic components as an effect requiring aging management.

- Wetted Gas: Wetted gas environments include air, containment atmosphere, and diesel exhaust gas. Air is either ambient or compressed air without air dryers in the system. Containment atmosphere in the drywell and torus is inerted with nitrogen with only 4% oxygen but is assumed to have the same corrosive effects as ambient air. Diesel exhaust can contain sulfur residues so exhaust system components an be exposed to moisture and sulfuric acid.

- Dry Gas: The dry gas environments include dried air, nitrogen, carbon dioxide, hydrogen, oxygen, and freon. These gases are considered inert with respect to corrosion because they have no significant moisture content.

To provide reasonable assurance that the aging effects that require management for a specific material-environment combination are the only aging effects of concern for Peach Bottom, the applicant also performed a review of industry experience and NRC generic communications relative to the engineered safety features structures and components. In addition, relevant Peach Bottom operating experience was reviewed to provide additional confidence that all aging effects for the specific material-environment combinations have been identified.

3.4.1 Main Steam System

3.4.1.1 Technical Information in the Application

The Peach Bottom main steam system conducts steam from the reactor vessel through the primary containment to the steam turbine over the full range of reactor power operation. Four steam lines are utilized between the reactor and the main turbine. The use of multiple lines permits turbine stop valve and main steam line isolation valve testing during plant operation with a minimum amount of load reduction.

3.4.1.1.1 Aging Effects

Table 3.4-1 of the LRA identified the following components that will require aging management during the extended period of operation: piping, pipe specialties (flow elements, dashpot, Y strainer, condensing chambers, spargers, restricting orifices, flexible hoses), tubing, accumulators, and valve bodies. The applicant identified stainless steel, carbon steel, copper, and brass as the materials of construction for the main steam components.

3.4.1.1.2 Aging Management Programs

The LRA identified five aging management programs to manage the aging effects in the main steam system during the extended period of operation. These five programs are:

- RCS Chemistry Program
- ISI Program
- Torus Piping Inspection Program
- FAC Program
- Torus Water Chemistry Program

3.4.1.2 Staff Evaluation

The staff reviewed the information included in Section 3.4 of the LRA. The purpose of the review was to ascertain whether the applicant has adequately demonstrated that the effects of aging associated with the main steam system will be adequately managed so that the intended function of the system will be maintained consistent with the CLB throughout the period of extended operation in accordance with 10 CFR 54.21(a)(3).

3.4.1.2.1 Aging Effects

The LRA included a summary of the results of the aging management review for the main steam system. The results are listed in Table 3.4-1 of the LRA. The materials of construction, applicable environments, and aging effects for the main steam system are as follows:

- stainless steel, carbon steel, brass and copper in dry gas and sheltered environments—no aging effects
- carbon steel in a steam environment— loss of material
- stainless steel in a steam environment—loss of material and cracking
- carbon steal in a wetted gas environment—loss of materials
- stainless steel in a wetted gas environment—cracking
- carbon steel in a torus-grade water environment—loss of material

No aging effects were identified in the AMR of piping, piping specialties, accumulators, tubing, and valve bodies made of stainless steel, carbon steel, brass or copper in a dry gas or sheltered environment. These materials are resistant to corrosion in both dry gas and sheltered environments. The applicant, therefore, has not identified any applicable aging effects for the surfaces of stainless steel, carbon steel, brass, or copper main steam system components exposed to these environments.

Loss of material was identified for carbon steel piping, piping specialties, and valve bodies in steam environments. Loss of material of carbon steel materials by corrosion may occur in steam environment, and therefore may be an applicable aging effect for carbon steel surfaces exposed to steam. The applicant will use the RCS chemistry program, ISI program, and FAC program to manage loss of material for carbon steel piping, piping specialties, and valve bodies.

Loss of material and cracking were identified for the stainless steel piping, piping specialties, and tubing in steam environments. Loss of material and cracking of stainless steel materials may occur in steam environment, and therefore may be an applicable aging effect for stainless steel surfaces exposed to steam. The applicant will use the RCS chemistry program and ISI program to manage loss of material for stainless steel piping, piping specialties, and tubing in a steam environment.

Loss of material was identified for the carbon steel piping, and valve bodies in wetted gas environments. Loss of material of carbon steel materials by corrosion may occur in a wetted gas environment, and therefore may be an applicable aging effect for carbon steel surfaces exposed to wet gas. The applicant will use the ISI program and Torus Piping Inspection program to manage loss of material for carbon steel piping and valve bodies in a wetted gas environment.

Cracking of material was identified for the stainless steel piping, piping specialties, and valve bodies in wetted gas environments. Cracking of stainless steel materials may occur in a wetted gas environment, and therefore may be an applicable aging effect for stainless steel surfaces exposed to wet gas. The applicant will use the ISI program to manage cracking associated with stainless steel piping, piping specialties, and valve bodies in wetted gas environment.

Loss of material was identified for carbon steel piping and piping specialties in a torus-grade water environment. Loss of material of carbon steel materials by corrosion may occur in torus-grade water environment, and therefore may be an applicable aging effect for carbon steel surfaces exposed to torus water. The applicant will use the Torus Water Chemistry program and Torus Piping Inspection program to manage loss of material for carbon steel piping and piping specialties in a torus-grade water environment.

3.4.1.2.2 Aging Management Programs

The applicant stated that the RCS chemistry program, ISI program, and FAC program will be used to manage the loss of material associated with carbon steel piping, piping specialties, and valve bodies. The RCS chemistry program and ISI program will be used to manage the loss of material associated with stainless steel piping, piping specialties, and tubing in a steam environment. The ISI program and Torus Piping Inspection program will be used to manage the loss of material associated with carbon steel pipe, and valve bodies in a wetted gas environment. The ISI program will be used to manage cracking associated with stainless steel pipe, pipe specialties, and valve bodies in a wetted gas environment. The Torus Water Chemistry program and Torus Piping Inspection program will be used to manage the loss of material associated with carbon steel piping and piping specialties in a torus-grade water environment. Detailed description concerning each of the programs identified above is included in Appendix B to the LRA, along with a demonstration that the identified aging effects will be effectively managed for the period of extended operation. The staff's detailed review of the different aging management activities and their ability to adequately manage the applicable aging effects is provided in Section 3.0.3.5 and 3.0.3.21 of this SER. As a result of this review, the staff did not identify any concerns or omissions in the aging management activities used to manage the main steam system.

3.4.1.3 Conclusions

The staff has reviewed the information in Section 3.4, "Aging Management of Steam and Power Conversion Systems," of the LRA. On the basis of its review, the staff concludes that the applicant's identification of the aging effects associated with the main steam system is consistent with published literature and industry experience. The staff further concludes that the applicant has adequate aging management programs to effectively manage the aging effects of the main steam system and that there is reasonable assurance that the intended functions of the system will remain consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.4.2 Main Condenser

3.4.2.1 Technical Information in the Application

The Peach Bottom main condenser provides a heat sink for the turbine exhaust steam and turbine bypass steam. It also deaerates and stores the condensate for reuse after a period of radioactive decay. Additionally, the main condenser provides for post-accident containment, holdup, and plateout of main steam isolation valve (MSIV) bypass leakage.

The main condenser is a single-pass, single-pressure, deaerating type with a reheating deaerating hotwell and divided waterboxes. The condenser consists of three sections, each located below the low-pressure elements of the turbine, with the tubes oriented transverse to the turbine-generator axis. The steam exhausts directly down into the condenser shells through exhaust openings in the bottom of each low-pressure turbine casing. The condensers also receive steam from the reactor feed pump turbines.

3.4.2.1.1 Aging Effects

Table 3.4-2 of the LRA identified the following components of the main condenser as subject to AMR: main condenser shell, tubesheet, tubes, waterbox, feedwater heater shell, drain cooler shell, nozzles, and expansion joints. No aging effects requiring aging management during the period of extended operation were identified for these components. The applicant identified stainless steel, carbon steel, and titanium as the materials of construction for the main condenser components.

3.4.2.1.2 Aging Management Programs

The LRA identified no aging management programs to manage the aging effects for the main condenser during the extended period of operation.

3.4.2.2 Staff Evaluation

The staff has reviewed the information included in Section 3.4 of the LRA. The purpose of the review was to ascertain whether the applicant has adequately demonstrated that the effects of aging associated with the main condenser will be adequately managed so that the intended function of the main condenser will be maintained consistent with the CLB throughout the period of extended operation as required by 10 CFR 54.21(a)(3).

3.4.2.2.1 Aging Effects

The LRA included a summary of the results of the aging management review for the main condenser. The results are listed in Table 3.4-2 of the LRA. The materials of construction, applicable environments and aging effects for the main condenser are as follows:

- carbon and stainless steel in a steam environment—no aging effects
- carbon and stainless steel in reactor coolant and raw water environments—no aging effects
- titanium tubes in steam and raw water environments—no aging effects

No aging effects were identified by the AMR for the main condenser components made of carbon steel, stainless steel, or titanium in steam, reactor coolant, or raw water environments. These materials have successfully performed as main condenser materials at other plants. Further, the applicant has concluded that aging management of the main condenser is not based on analysis of materials, environments, and aging effects. Condenser integrity required to perform the post-accident intended function (holdup and plateout of MSIV leakage) is continuously confirmed by normal plant operation. The main condenser must perform a significant pressure boundary function (maintain vacuum) to allow continued plant operation. For these reasons, the applicant has not identified any applicable aging effects for the main condenser. The staff concurs with the applicant's conclusion because the main condenser integrity is continuously confirmed during normal plant operation and thus the condenser post-accident function will be ensured.

3.4.2.2.2 Aging Management Programs

The applicant did not identify any management programs to manage aging effects for the main condenser materials because no aging effects were identified as applicable to the main condenser. The above-identified main condenser materials have successfully performed as main condenser materials at other plants with no problems being reported. Further, the applicant has concluded that the main condenser must perform a significant pressure boundary function (maintain vacuum) to allow continued plant operation. The staff concurs with the applicant's conclusion that the main condenser does not require aging management because the main condenser integrity is continuously tested and confirmed during normal plant operation.

3.4.2.3 Conclusions

The staff has reviewed the information in Section 3.4, "Aging Management of Steam and Power Conversion Systems," of the LRA. On the basis of its review, the staff concludes that the applicant's assessment of the aging effects associated with the main condenser is consistent with published literature and industry experience. The staff further concludes that the applicant does not need aging management programs to manage the aging effects because the main condenser integrity is continuously confirmed during normal plant operation and thus the condenser post-accident function will be ensured consistent with the CLB throughout the extended period of operations.

3.4.3 Feedwater System

3.4.3.1 Technical Information in the Application

The Peach Bottom feedwater system receives its supply of water from the outlet of the condensate demineralizers during normal plant operation. The system consists of three feedwater heater strings (with cascading drains) connected in parallel, each consisting of five low-pressure feedwater heaters and one drain cooler in series. The feedwater heaters receive steam from the main turbine system and preheat feedwater before it enters the reactor feed pumps, thus increasing the heat cycle efficiency.

3.4.3.1.1 Aging Effects

Table 3.4-3 of the LRA identified the following components as requiring aging management during the extended period of operation: piping, piping specialties, tubing, and valve bodies. The applicant identified carbon and stainless steel as the materials of construction for the feedwater components.

3.4.3.1.2 Aging Management Programs

The LRA identified three aging management programs that will manage the aging effects on the main steam system during the extended period of operation:

- RCS Chemistry Program
- ISI Program
- FAC Program

3.4.3.2 Staff Evaluation

The staff has reviewed the information included in Section 3.4 of the LRA. The purpose of the review was to ascertain whether the applicant has adequately demonstrated that the effects of aging associated with the feedwater system will be adequately managed so that the intended function of the system will be maintained consistent with the CLB throughout the period of extended operation as required by 10 CFR 54.21(a)(3).

3.4.3.2.1 Aging Effects

The LRA included a summary of the results of the aging management review for the feedwater system. The results are listed in Table 3.4-3 of the LRA. The materials of construction, applicable environments, and aging effects for the feedwater system are as follows:

- carbon and stainless steel in a sheltered environment—no aging effects
- carbon steel in a reactor coolant environment—loss of material
- stainless steel in a reactor coolant environment—cracking

No aging effects were identified by the AMR for piping, piping specialties, tubing, and valve bodies made of stainless steel or carbon steel in a sheltered environment. These materials are corrosion resistant in sheltered environments. The applicant, therefore, has not identified any applicable aging effects for the surfaces of stainless steel or carbon steel feedwater system components exposed to this environment.

Loss of material was identified for the carbon steel piping, piping specialties, and valve bodies in a reactor coolant environment. Loss of material of carbon steel by corrosion may occur in reactor coolant environment, and therefore may be an applicable aging effect for the carbon steel surfaces exposed to reactor coolant water. The applicant will use the RCS chemistry program, ISI program, and FAC program to manage loss of material for carbon steel piping, piping specialties, and valve bodies.

Cracking was identified for the stainless steel pipe, tubing, and valve bodies in a reactor coolant environment. Cracking of stainless steel materials may occur in reactor coolant environment, and therefore may be an applicable aging effect for the stainless steel surfaces exposed to reactor coolant. The applicant will use the RCS chemistry program to manage the loss of material associated with stainless steel pipe, tubing, and valve bodies in a reactor coolant environment.

3.4.3.2.2 Aging Management Programs

The applicant stated that the RCS chemistry program, ISI program, and FAC program will be used to manage the loss of material associated with carbon steel piping, piping specialties, and valve bodies. The RCS chemistry program will be used to manage the loss of material associated with stainless steel pipe, tubing, and valve bodies in a reactor coolant environment. A detailed description of each of the programs identified above is included in Appendix B to the LRA, along with a demonstration that the identified aging effects will be effectively managed for the period of extended operation. The staff's detailed review of the different aging management activities and their ability to adequately manage the applicable aging effects is provided in Appendix B of this SER. As a result of its review, the staff did not identify any concerns or omissions in the aging management activities used to manage the feedwater system.

3.4.3.3 Conclusions

The staff has reviewed the information in Section 3.4, "Aging Management of Steam and Power Conversion Systems," of the LRA. The staff considered both industry and plant-specific experience. On the basis of its review, the staff concludes that the applicant's identification of the aging effects associated with the feedwater system is consistent with published literature and industry experience. The staff further concludes that the applicant has adequate aging management programs to effectively manage the aging effects of the feedwater system and that there is reasonable assurance that the intended functions of the system will remain consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.5 Aging Management of Structures and Component Supports

3.5.1 Containment Structure

3.5.1.1 Technical Information in the Application

The aging management review results for the containment structure, which consists of the primary containment of each unit and internal structural steel, are presented in Table 3.5-1 of the LRA. Table 3.5-1 of the LRA identifies the components of the containment structure along with their (1) intended functions, (2) environments, (3) materials, (4) aging effects, and (5) aging management activities.

Section 2.4.1 of the LRA states that the containment structure consists of the primary containment of each unit and internal structural steel. The primary containment of each unit is of the Mark I design and consists of a drywell, a suppression chamber in the shape of a torus, and a connecting vent system between the drywell and suppression chamber. The containment structure is also an enclosure for the reactor vessel, the reactor coolant recirculation system, and other branch connections of the reactor coolant system. The drywell is a steel pressure vessel in the shape of a light bulb, and is enclosed in reinforced concrete for shielding purposes. The pressure suppression chamber is a torus-shaped steel pressure vessel located below and encircling the drywell. It contains approximately 125,000 cu ft of water and has a gas space volume above the pool. The pressure suppression chamber is supported on braced vertical columns to carry its loading to the reinforced concrete foundation slab of the reactor building. Internal structural steel is used at various elevations of the drywell and suppression chamber to provide structural support to safety-related and non-safety-related systems and equipment inside the drywell.

The materials of construction for the containment structure, as shown in Table 3.5-1 of the LRA, are concrete, carbon steel, stainless steel, elastomers, bronze, and graphite. The pressure suppression chamber gaskets and drywell gaskets are made of ethylene propylene dienyl monomer (EPDM).

The containment structure components are exposed to an internal or sheltered environment and some vent system and pressure suppression chamber components are exposed to torus water.

3.5.1.1.1 Aging Effects

Table 3.5-1 of the LRA identifies the following applicable aging effects for components in the containment structure:

- loss of material of carbon and stainless steel components in sheltered or torus water environments
- cumulative fatigue damage of carbon and stainless steel components in sheltered or torus water environments
- change in material properties and cracking of elastomers in a sheltered environment

The applicant did not identify loss of material or cumulative fatigue damage for all of the carbon steel components in the containment structure; however, either one or both of these aging effects are identified for all in-scope stainless steel components in the containment structure.

3.5.1.1.2 Aging Management Programs

Table 3.5-1 of the LRA credits the following two aging management activities with managing the identified aging effects for the components in the containment structure:

- Primary Containment ISI Program
- Primary Containment Leakage Rate Testing Program

A description of these two aging management activities is provided in Appendix B of the LRA. For the cumulative fatigue damage aging effect for steel components in the containment structure, the applicant credits various time-limited aging analyses (TLAAs), which are described in Section 4 of the LRA. The applicant concludes that the effects of aging associated with the components in the containment structure will be adequately managed by these aging management activities such that there is reasonable assurance that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.5.1.2 Staff Evaluation

In addition to Section 3.5 of the LRA, the staff reviewed the pertinent information provided in Section 2.4, “Scoping and Screening Results: Structures and Component Supports” and the applicable aging management program descriptions provided in Appendix B of the LRA to determine whether the aging effects for the containment components have been properly identified and will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

This section of this SER provides the staff’s evaluation of the applicant’s aging management review for the aging effects and the applicant’s programs credited for the aging management of the containment at each Peach Bottom unit. The staff’s evaluation includes a review of the aging effects considered and the basis for the applicant’s elimination of certain aging effects. In addition, the staff has evaluated the applicability of the aging management programs that are credited for managing the identified aging effects for the containment components.

3.5.1.2.1 Aging Effects

Concrete: No aging effects are identified in Table 3.5-1 for the concrete containment components. These concrete containment components are the (1) reinforced concrete reactor pedestal, foundation, and floor slab and (2) the unreinforced concrete sacrificial shield wall. All of these concrete containment components are exposed to a sheltered environment.

The staff considers cracking, change in material properties, and loss of material to be applicable aging effects for concrete containment components that are exposed to sheltered or outdoor environments. The NRC staff position regarding the aging management of in-scope concrete structures and components (SCs) is that they need to be periodically inspected in order to adequately monitor their performance or condition in a manner that allows for the timely identification and correction of degraded conditions. Concrete SCs in nuclear power plants are prone to various types of age-related degradation, depending on the stresses and strains due to normal and incidental loadings and the environment to which they are subjected. Concrete SCs subjected to sustained loading, such as crane or monorail operation, and/or sustained adverse environmental conditions, such as high temperatures, humidity, or chlorides, will degrade, thereby potentially affecting the intended functions of the SCs. These degradations to concrete SCs are manifested through aging effects such as cracking, loss of material, and change in material properties. As concrete SCs age, such aging effects accentuate. On the basis of industry-wide evidence, the American Concrete Institute (ACI) has published a number of documents (e.g., ACI 201.1R, "Guide for Making a Condition Survey of Concrete," ACI 224.1R, "Causes, Evaluation and Repairs of Cracks in Concrete Structures," and ACI 349.3R, "Evaluation of Existing Nuclear Safety-Related Concrete Structures") that identify the need to manage the aging of concrete structures. These reports and standards confirm the inherent tendency of concrete structures to degrade over time if not properly managed. Similar observations of concrete aging made by NRC staff are detailed NUREG-1522, "Assessment of In-Service Conditions of Safety-Related Nuclear Power Plant Structures." Accordingly, in RAI 3.5-1 the staff requested that the applicant identify the aging management program(s) that will be used to manage the aging effects for the concrete containment components listed in Table 3.5-1 of the LRA.

In response, the applicant stated:

> PBAPS aging management reviews (AMRs) concluded that concrete and block wall aging effects are non-significant, will not result in a loss of intended function, and thus require no aging management. The AMRs are based on guidelines for implementing the requirements of 10 CFR Part 54, developed jointly by the NRC and the industry, that are documented in NEI 95-10. The AMR results are also confirmed by PBAPS operating experience.
>
> Exelon therefore is not in agreement with the staff's position, that PBAPS concrete and block wall aging effects require aging management. However, we recognize that, contrary to our experience, the staff is concerned that unless concrete and block wall aging effects are monitored they may lead to a loss of intended function. As a result, we will monitor concrete and block wall structures

> in accessible areas, for loss of material, cracking and change in material properties. The PBAPS Maintenance Rule Structural Monitoring Program (B.1.16) will be used to monitor the structures.

The applicant's commitment to monitor concrete and block wall aging effects in accessible areas is acceptable to the staff. The applicant has decided to use the Maintenance Rule Structural Monitoring Program to manage concrete aging. This program is reviewed in Section 3.0.3.11 of this SER.

For below-grade concrete components, the staff has determined that aging management is unnecessary if applicants are able to show that the below-grade soil/groundwater environment is nonaggressive. In response to RAI 3.5-1, the applicant provided water chemistry results that show that the Peach Bottom soil/groundwater environment is nonaggressive (pH = 7.2, sulfates = 38 ppm, and chlorides = 24 ppm). Consequently, the applicant concluded that the aging management of below-grade concrete is not required. Since the groundwater chemistry at the Peach Bottom site is well above the limit for pH (5.5) and below the limits for sulfates (1500 ppm) and chlorides (500 ppm), the staff concurs with the applicant's conclusion that the groundwater is nonaggressive with respect to concrete. Therefore, below-grade concrete does not need to be managed by the applicant.

The staff considers the applicant's response to RAI 3.5-1 to be adequate with respect to managing the aging of concrete and masonry block walls during the period of extended operation.

Steel: The applicant identified (1) loss of material of carbon and stainless steel components in sheltered or torus water environments and (2) cumulative fatigue damage of carbon and stainless steel components in sheltered or torus water environments as applicable aging effects for steel components in the containment structure.

The staff concurs with the aging effects identified above by the applicant for the carbon steel and stainless steel components in the containment structure. However, the staff noted in Part 1 of RAI 3.5-2, that no aging effects are identified in Table 3.5-1 for the carbon steel structural supports, pipe whip restraints, missile barriers, and radiation shields in the containment structure. In response to Part 1 of RAI 3.5-2, the applicant stated:

> PBAPS aging management reviews (AMRs) concluded that carbon steel exposed to a sheltered environment would be subjected to non-significant loss of material due to atmospheric corrosion. The estimated reduction in material thickness will not significantly degrade the load bearing capacity of structural members and thus will not adversely impact their intended function. The AMRs are based on guidelines for implementing the requirements of 10 CFR Part 54, developed jointly by the NRC and the industry, and are documented in NEI 95-10. The AMR results are also confirmed by PBAPS operating experience.
>
> Exelon's position is that loss of material for carbon steel in PBAPS sheltered environment is non-significant and requires no aging management. The position is supported by AMRs performed in accordance with industry guidelines for implementing the requirements of 10 CFR Part 54, and PBAPS operating experience. The position and its justification were discussed with NRC staff on

January 28, 2002 in a telephone call. The staff indicated that it does not agree with the Exelon position and an aging management activity is required to ensure the intended function is maintained through the extended term of operation. As a result, Exelon will monitor carbon steel components in a sheltered environment as described below.

- Containment Structure (Table 3.5-1). Carbon steel components in accessible areas inside containment (i.e. structural supports, pipe whip restraints, missile barriers, and radiation shields) will be monitored for loss of material due to corrosion. The PBAPS Maintenance Rule Structural Monitoring Program (B.1.16) will be used for structural steel components other than Class MC component supports. Class MC component supports will be monitored using the Primary Containment ISI Program (B.1.9).

The applicant's commitment to monitor carbon steel components inside containment for loss of material is acceptable to the staff. The applicant has decided to use the Maintenance Rule Structural Monitoring Program to manage structural steel components other than Class MC component supports. For Class MC component supports, the applicant has committed to using the Primary Containment ISI Program. The staff considers Part 1 of RAI 3.5-2 to be closed.

Elastomers (seals, gaskets, O-rings): Table 3.5-1 of the LRA identifies cracking and change in material properties as aging effects for the elastomer components in the containment structure. The staff concurs with the applicant's identification of these two aging effects for elastomers associated with the primary containment pressure boundary components.

Bronze/Graphite: Table 3.5-1 of the LRA does not identify any aging effects for the bronze/graphite Lubrite plates in the containment structure. In Part 1 of RAI 3.5-3, the staff requested further information regarding the applicant's AMR for Lubrite plates. In response, the applicant stated:

> Lubrite is the trade name for a low-friction lubricant material used in applications where relative motion (sliding) is desired. At PBAPS, lubrite plates are incorporated in the design of limited component supports to reduce or release horizontal loads due to temperature transients and SRV discharges.
>
> PBAPS AMRs determined that there are no known aging effects for the lubrite material that would lead to a loss of intended function. As explained by previous applicants and concurred by the staff, lubrite resists deformation, has a low coefficient of friction, resists softening at elevated temperatures, absorbs grit and abrasive particles, is not susceptible to corrosion, withstands high intensities of radiation, and will not score or mar. In addition, lubrite products are solid, permanent, completely self-lubricating, and require no maintenance as documented in NUREG-1759, "Safety Evaluation Report Related to the License Renewal of Turkey Point Nuclear Plant, Units 3 and 4." A search of PBAPS and industry operating experience found no reported instances of lubrite plate degradation or failure to perform their intended function. On this basis, Exelon maintains that lubrite plates require no aging management.

The staff concurs with the applicant's response to RAI 3.5-3 with respect to the need for managing the aging of lubrite plates. The applicant's AMR of lubrite material is consistent with industry experience. The staff considers Part 1 of RAI 3.5-3 to be closed.

3.5.1.2.2 Aging Management Programs

Table 3.5-1 of the LRA credits the following aging management programs with managing the identified aging effects for the components in the containment structure:

- Primary Containment ISI Program
- Primary Containment Leakage Rate Testing Program

In addition, in response to RAIs 3.5-1 and 3.5-2 the applicant has committed to using the Maintenance Rule Structural Monitoring Program to manage the aging effects for several additional concrete and structural steel components in the containment structure. The Maintenance Rule Structural Monitoring Program, Primary Containment ISI Program, and Primary Containment Leakage Rate Testing Program are credited with managing the aging of several components in several different structures and systems and are, therefore, considered common aging management programs. The adequacy of seals and gaskets associated with the primary containment pressure boundary is assessed under the primary containment leakage rate testing program in SER Section 3.0.3.8. The staff review of the common aging management programs is in Section 3.0 of this SER.

3.5.1.3 Conclusions

The staff has reviewed the information in Section 3.5 of the LRA as well as the applicable aging management program descriptions in Appendix B of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the components in the containment structure will be adequately managed so that there is reasonable assurance that these components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.5.2 Reactor Building Structure

3.5.2.1 Technical Information in the Application

The aging management review results for the reactor building structure are presented in Table 3.5-2 of the LRA. Table 3.5-2 of the LRA identifies the components that constitute the reactor building structure along with their (1) intended functions, (2) environments, (3) materials of construction, (4) aging effects, and (5) aging management activities.

Section 2.4.2 of the LRA states that the reactor building for each unit is a seismic Class I structure completely enclosing the primary containment and auxiliary systems of the nuclear steam supply system and housing the associated spent fuel storage pool, dryer and separator storage pool, and reactor well. The building is a reinforced concrete structure from its foundation floor to its refueling floor. Above this floor, the building superstructure consists of metal siding and roof decking supported on structural steel framework. The foundation of the building consists of a reinforced concrete mat supported on rock. This mat also supports the primary containment and its internals, including the reactor vessel pedestal. The exterior and some interior walls of the building above the foundation are cast-in-place concrete. Other interior walls are normal weight concrete block walls. Floor slabs of the buildings are of composite construction with cast-in-place concrete over structural steel beams and metal floor deck. The thickness of walls and slabs was governed by structural requirements or shielding requirements. The steel-framed superstructure is cross-braced to withstand wind and earthquake forces and supports metal siding, metal roof deck, and roofing. The frame also supports a runway for the 125-ton traveling reactor building crane.

The materials of construction for the reactor building structure, as shown in Table 3.5-2 of the LRA, are concrete, masonry block, carbon steel, stainless steel, and aluminum. Boraflex is used for Boraflex absorbers.

The reactor building structure components are exposed to buried, outdoor, sheltered, and fuel pool water environments.

3.5.2.1.1 Aging Effects

Table 3.5-2 of the LRA identifies the following applicable aging effects for components in the reactor building structure:

- loss of material of carbon steel components in an outdoor environment
- loss of material of stainless steel components in a fuel pool water environment
- loss of material of aluminum components in a fuel pool water environment
- change in material properties of Boraflex in a fuel pool water environment

3.5.2.1.2 Aging Management Programs

Table 3.5-2 of the LRA credits the following aging management activities with managing the identified aging effects for the components in the reactor building structure:

- Fuel Pool Chemistry program
- Maintenance Rule Structural Monitoring Program
- Boraflex Management Activities program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components in the reactor building structure will be adequately managed by these aging management programs such that there is reasonable assurance that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.5.2.2 Staff Evaluation

In addition to Section 3.5 of the LRA, the staff reviewed the pertinent information provided in Section 2.4, “Scoping and Screening Results: Structures and Component Supports,” and the applicable aging management program descriptions provided in Appendix B of the LRA to determine whether the aging effects for the reactor building structure components have been properly identified and will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

This section of this SER provides the staff's evaluation of the applicant's aging management review for the aging effects and the applicant's programs credited for the aging management of the reactor building structure at each Peach Bottom unit. The staff's evaluation includes a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the applicability of the aging management programs that are credited for managing the identified aging effects for the reactor building components.

3.5.2.2.1 Aging Effects

Concrete: The applicant did not identify any applicable aging effects for the reinforced concrete walls, slabs, columns, beams, and foundation that make up the reactor building structure. In addition, the applicant did not identify any aging effects for the reinforced concrete block walls within the reactor building structure.

As noted above in Section 3.5.1.2.1 of this SER, the staff considers loss of material, cracking, and change in material properties to be both plausible and applicable aging effects for all concrete components, including masonry block walls, in all of the environments listed by the applicant. The NRC staff position regarding the aging management of in-scope concrete structures and components (SCs) is that they need to be periodically inspected in order to adequately monitor their performance or condition in a manner that allows for the timely identification and correction of degraded conditions. In RAI 3.5-1, the staff requested further information regarding the applicant's AMR of concrete components and specifically, the applicant's determination that management of concrete aging is not required. In response to RAI 3.5-1, the applicant stated that it is not in agreement with the staff's position regarding the aging management of concrete structures; however, the applicant has decided that it will manage concrete and masonry block wall aging during the period of extended operation. The applicant specifically stated that it will monitor concrete and masonry block wall structures for loss of material, cracking, and change in material properties through the Maintenance Rule Structural Monitoring Program. Since this commitment from the applicant covers the outdoor and sheltered reactor building structure concrete components, this response is considered acceptable by the staff. RAI 3.5-1 is considered closed with respect to the outdoor and sheltered reactor building concrete components.

For the buried reactor building concrete components, the staff has determined that aging management is unnecessary if applicants are able to show that the below-grade soil/groundwater environment is nonaggressive. In response to RAI 3.5-1, the applicant provided water chemistry results that show that the Peach Bottom soil/groundwater environment is nonaggressive (pH = 7.2, sulfates = 38 ppm, and chlorides = 24 ppm). Consequently, the applicant concluded that the aging management of below-grade concrete is not required. Since the groundwater chemistry at the Peach Bottom site is well above the limit for pH (5.5) and below the limits for sulfates (1500 ppm) and chlorides (500 ppm), the staff concurs with the applicant's conclusion that the groundwater is nonaggressive with respect to concrete. Therefore, below-grade concrete does not need to be managed by the applicant.

Steel: The applicant identified (1) loss of material of carbon steel components in an outdoor environment and (2) loss of material of stainless steel components in a fuel pool water environment as applicable aging effects for steel components in the reactor building structure.

The staff concurs with the aging effects identified above by the applicant for the carbon steel and stainless steel components in the reactor building structure. However, the staff noted in Part 2 of RAI 3.5-2, that no aging effects are identified in Table 3.5-2 for the carbon steel components in a sheltered environment within the reactor building structure. In response to Part 2 of RAI 3.5-2, the applicant stated that it disagrees with the staff's position that carbon steel components in a sheltered environment require aging management. However, in response to RAI 3.5-2, the applicant committed to monitor carbon steel components in a sheltered environment for loss of material. Included in this commitment are all of the carbon steel components in the reactor building exposed to a sheltered environment for which the applicant did not originally identify any aging effects. Therefore, the staff considers the applicant's response to RAI 3.5-2 to be adequate.

Aluminum: Table 3.5-2 of the LRA identifies loss of material as an applicable aging effect for the aluminum fuel pool gates and component supports. For the portion of the aluminum fuel pool gates in a sheltered environment (above the fuel pool water level), the applicant did not identify any aging effects. The staff concludes that the applicant has properly identified the applicable aging effect for the aluminum components in the reactor building structure that are exposed to fuel pool water.

Boraflex: Table 3.5-2 of the LRA identifies change in material properties for the Boraflex absorbers in the fuel pool as an applicable aging effect. The staff concurs with the applicant's identification of change in material properties as an applicable aging effect for the Boraflex absorbers in the fuel pool. To manage the aging of the Boraflex absorbers, the applicant has proposed to use the Boraflex Management Activities aging management program.

3.5.2.2.2 Aging Management Programs

Table 3.5-2 of the LRA credits the following aging management activities with managing the identified aging effects for the components in the reactor building structure:

- Fuel Pool Chemistry
- Maintenance Rule Structural Monitoring Program
- Boraflex Management Activities

The Maintenance Rule Structural Monitoring Program is credited with managing the aging of several components in several different structures and systems and is, therefore, considered a common aging management program. The staff review of the common aging management programs is in Section 3.0 of this SER. The staff evaluations of the Fuel Pool Chemistry and the Boraflex Management Activities programs are given below.

<u>Boraflex Management Activities Program</u>

Boraflex Management Activities

The applicant described the Boraflex management activities AMP in Section B.2.2 of Appendix B of the LRA. The staff reviewed the applicant's description of the AMP in Section B.2.2 of the LRA to determine whether the applicant has demonstrated that the Boraflex management activities AMP will adequately manage the effects of aging of the spent fuel rack neutron poison material during the period of extended operation as required by 10 CFR 54.21(a)(3).

Technical Information In the Application

The applicant described the Boraflex management activities aging management program (AMP) in Section B.2.2 of the LRA. The applicant stated that this AMP provides for aging management of the spent fuel rack neutron poison material. The applicant stated that these activities include the monitoring of the condition of Boraflex by routinely sampling fuel pool silica levels and periodically performing in situ measurements of boron-10 areal density. These activities are based on EPRI guidelines.

The applicant found that since this AMP is based on the use of industry guidelines and PBAPS and industry operating experience, there is reasonable assurance that the Boraflex management activities will continue to adequately manage the effects of aging of spent fuel rack Boraflex so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

Staff Evaluation

The staff's evaluation of the Boraflex management activities focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicates that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

Program Scope: The applicant described the program scope of the PBAPS Boraflex management activities as managing the effects of spent fuel rack Boraflex material degradation to ensure that the intended function is maintained. The applicant further stated that these activities are based on EPRI guidelines and include routine monitoring and trending of silica in the spent fuel pool and periodically performing in situ measurement of boron-10 areal density. The staff found the scope of the program to be acceptable because the applicant adequately addressed the components whose aging effects could be managed by the application of the Boraflex management activities.

Preventive or Mitigative Actions: The Boraflex management activities AMP monitors the condition of Boraflex to ensure that its degradation is detected before a loss of intended function. No preventive or mitigative attributes are associated with these activities. The staff found this program attribute acceptable because the staff considers monitoring activities a means of detecting, not preventing, aging and, therefore, agrees that there are no preventive actions associated with this AMP.

Parameters Monitored or Inspected: The silica in fuel pool water is monitored for indication of loss of boron from the matrix and degradation of the matrix itself. Measurement of the boron-

10 areal density of in-service spent fuel storage rack panels is used to monitor neutron attenuation capability. The staff found the monitoring of the parameters following EPRI guidelines to be adequate to mitigate aging degradation for the spent fuel rack neutron poison material.

Detection of Aging Effects: The applicant stated that Boraflex degradation from change in material properties will result in release of silica boron carbide from Boraflex and result in increased levels of silica in fuel pool water and loss of boron-10 areal density. The applicant further stated that these parameters are monitored in accordance with EPRI guidelines at a frequency that assures identification of unacceptable aging effects before loss of intended function. The staff indicated that the amount of boron carbide released from the Boraflex panel is determined through direct measurement of boron areal density and the levels of silica determined by the use of a predictive code such as RACKLIFE or other similar codes. Therefore, the staff requested additional information on the applicant's use of the data on silica levels and the loss of boron area density.

The applicant responded, in a letter to the NRC dated May 14, 2002, that the data on silica levels are monitored for the prediction of loss of boron carbide and would signal potential degradation of Boraflex. The applicant further stated that silica is also used as an input to the EPRI RACKLIFE computer code. The staff found this program attribute acceptable because the applicant follows EPRI guidelines which have long-been, accepted for industry use. The staff also found that the program activities may be relied upon to provide reasonable assurance that aging effects will be detected before there is loss of intended function.

Monitoring and Trending: The applicant stated that monitoring of change in material properties is accomplished through the periodic measurements of boron-10 areal density of in-service spent fuel storage rack panels and sampling of silica levels in fuel pool water. This data is used to trend and predict performance of Boraflex. The staff found the applicant's approach to monitoring and trending activities to be acceptable because it is based on methods that are sufficient to predict the extent of degradation so that timely corrective or mitigative actions are possible.

Acceptance Criteria: The applicant stated that analysis has shown that Boraflex will perform its intended function if degradation is maintained at less than a 10% uniform loss and at less than 10-cm randomly distributed gaps. The applicant described these parameter limits as ensuring that CLB fuel pool reactivity limits (keff > 0.95 or 5% margin) are not exceeded. The applicant further stated that spent fuel pool silica data are trended and compared to an industry-wide EPRI database. A sustained increasing trend in spent fuel pool silica concentration, inconsistent with previous seasonal/refueling changes, requires an engineering evaluation to determine the need for corrective action.

The staff requested additional information on the trending and comparison to an industry-wide database. The applicant responded, in a letter to the NRC dated May 14, 2002, that silica data is transmitted to EPRI periodically for analysis and trending and that the results are compared with data from other licensees who participate in the collaborative Boraflex research agreement with EPRI. The staff found the acceptance criteria specified by the applicant and the participation in an industry-wide data comparison agreement to be adequate to ensure the intended functions of the systems, structures, and components that may be served by the Boraflex management activities.

Operating Experience: The applicant stated that NRC Information Notices IN 87-43, IN 93-70, and IN 95-38 address several cases of significant degradation of Boraflex in spent fuel pools. In response to these findings, NRC issued Generic Letter 96- 04. The applicant further stated that the industry formed a Boraflex Working Group with EPRI and developed a strategy for tracking Boraflex performance in spent fuel racks, detecting the onset of material degradation, and mitigating its effects. The applicant described the Peach Bottom spent fuel racks and Boraflex as having been in service since 1986, and that in situ testing of representative Boraflex panels was conducted in 1996 for Unit 2 and 2001 for Unit 3. Test results identified Boraflex degradation; however, the degradation is less severe than experienced in the industry. The applicant indicated that continued testing would identify unacceptable degradation prior to loss of intended function. The staff found that the aging management activities described above are based on plant and industry experience and EPRI/industry working group participation. Therefore, the staff agreed that these activities are effective at maintaining the intended function of the systems, structures, and components that may be served by the Boraflex management activities, and can reasonably be expected to do so for the period of extended operation.

UFSAR Supplement

The staff reviewed Section A.2.2 of the UFSAR Supplement (Appendix A of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

Conclusions

The staff has reviewed the information provided in Section B2.2 of the LRA and the summary description of the Boraflex management activities in Section A.2.2 of the UFSAR Supplement (Appendix A of the LRA). In addition, the staff considered the applicant's response to the staff's RAIs provided in a letter to the NRC dated May 14, 2002. On the basis of this review and the above evaluation, the staff found that there is reasonable assurance that the applicant has demonstrated that the effect of aging within the scope of this evaluation will be adequately managed with the Boraflex management activities so that the intended functions will be maintained consistent with the CLB for the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

<u>Fuel Pool Chemistry Program</u>

Fuel Pool Chemistry Activities

The applicant described the fuel pool chemistry activities AMP in Section B1.6 of Appendix B of the LRA. The staff reviewed the applicant's description of the AMP in the LRA to determine whether the applicant has demonstrated that the fuel pool chemistry activities AMP will adequately manage the applicable effects of aging of components exposed to fuel pool water during the period of extended operation as required by 10 CFR 54.21(a)(3).

Technical Information in the Application

In Section B1.6 of the LRA, the applicant identified the fuel pool chemistry activities AMP as an existing aging management program that will be used by the applicant to manage loss of material of carbon steel and stainless steel components and cracking of stainless steel components exposed to fuel pool water in the fuel pool cooling and cleanup system. In addition, the applicant will use the fuel pool chemistry AMP to manage loss of material of the carbon steel and stainless steel components of the fuel pool gates, fuel storage racks, fuel pool liner, component supports, fuel preparation machines, and refueling platform mast. The fuel pool water is demineralized. Fuel pool water quality is monitored periodically and maintained in accordance with station procedures that include recommendations from EPRI TR-103515, "BWR Water Chemistry Guidelines."

Staff Evaluation

The staff's evaluation of the fuel pool chemistry activities focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicates that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

Program Scope: The applicant stated that the fuel pool chemistry activities AMP manages loss of material and cracking of components exposed to fuel pool water in the fuel pool cooling and cleanup system. The fuel pool chemistry AMP also manages loss of material of carbon steel and stainless steel components of the fuel pool gates, fuel storage racks, fuel pool liner, component supports, fuel preparation machines, and refueling platform mast. The AMP provides monitoring and controlling of detrimental contamination in the fuel pool water using the PBAPS procedures and processes based on EPRI TR-103515, "BWR Water Chemistry Guidelines" (the 2000 version). The staff found the scope of the program to be acceptable because it includes a comprehensive list of systems and components exposed to a fuel pool water environment.

Preventive or Mitigative Actions: The applicant indicated that the fuel pool chemistry activities AMP includes periodic monitoring and controlling of fuel pool water chemistry to maintain the contaminants within preestablished limits specified in EPRI TR-103515. The staff found that these procedures are adequate because they include all of the activities needed to mitigate age-related effects that are within the scope of license renewal.

Parameters Monitored or Inspected: The applicant identified the parameters to be monitored as conductivity, chlorides, and sulfates. The staff found these parameters acceptable because operating experience and the EPRI guidelines support the monitoring and control of these parameters to mitigate corrosion-related degradations and to ensure contaminants are not present in the fuel pool water.

Detection of Aging Effects: The applicant indicated that the fuel pool chemistry activities AMP mitigates the onset and propagation of loss of material and cracking aging effects; however, detection of aging effects is not credited. The staff believes that there should be a one-time inspection program to verify the effectiveness of the fuel pool water chemistry control to mitigate loss of material of the carbon steel component exposed to fuel pool water. Therefore, in RAI B1.6-1, the applicant was requested to include a one-time inspection in this AMP or explain the basis for not including a one-time inspection.

In a letter dated May 14, 2002, the applicant stated that PBAPS operating experience verifies the effectiveness of the fuel pool chemistry activities. The carbon steel components in the fuel pool cooling system as listed in Table 3.3-2 of the LRA are in the line from the RHR system to the fuel pool. This line was opened up and visually inspected in 2001 for Unit 3 and the results were satisfactory. The inspection of the similar line for Unit 2 is expected to be performed in 2004. Based on the applicant's approach, the staff agrees that a one-time inspection program is not necessary to verify the effectiveness of the fuel pool water chemistry control to mitigate the loss of material of the carbon steel component exposed to fuel pool water.

The staff believes that there should be a one-time inspection to verify the absence of cracking of stainless steel components exposed to fuel pool water because the fuel pool water could contain contaminants. In RAI B1.6-2, the staff asked the basis for not including the one-time inspection program to manage cracking of stainless steel components exposed to fuel pool water. In the same letter dated May 14, 2002, the applicant stated that the operating experience cited in the response to RAI B1.6-1 is also applicable RAI B1.6-2 for verifying the effectiveness of the fuel pool chemistry activities.

The applicant stated that EPRI TR-103840, "BWR Containment License Renewal Industry Report," and NUREG–0313, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping," consider stainless steel susceptible to significant cracking only at operating temperatures above 200 °F. The fuel pool water normal operating temperature is 85 °F with a high limit of 130 °F. These temperatures are significantly lower than the 200 °F referenced in the EPRI report. Consequently, cracking is not considered to be a significant aging effect for the fuel pool liner and components requiring aging management beyond the fuel pool chemistry activities. The staff found the response acceptable and agrees that this AMP does not have aging detection capability and that its use is to maintain a fuel water chemistry environment that will minimize aging effects such as loss of material and cracking.

Monitoring and Trending: The applicant indicated that periodic sampling measurements are taken and analyzed, and the data are trended. The minimum frequency of sampling is once per day for conductivity and once per week for chlorides and sulfates based on EPRI TR-103515. The staff found the frequency of sampling to be adequate in providing data for trending and that the fuel pool chemistry AMP would provide early indication of chemistry deviations, allowing for timely corrective action.

Acceptance Criteria: The specific limits of fuel pool chemistry are conductivity (< 2 µS/cm), chlorides (< 100 ppb), and sulfates (< 100 ppb). The minimum sampling frequency is once a week. These parameters and their maximum levels and minimum frequency of measurements are based on the values specified in EPRI TR-103515 for the fuel pool water. The staff found these values acceptable because they are consistent with the EPRI guideline, which is based on operating experience and has proven effective.

Operating Experience: The fuel pool chemistry activities AMP is an existing program. The applicant stated that components within the scope of license renewal have not experienced any loss of function such as failure of pressure boundary due to exposure to fuel pool water. The staff found that the fuel pool chemistry activities program has been effective in managing the aging effects associated with the systems and components exposed to fuel pool water.

UFSAR Supplement

The staff reviewed Section A.1.6 of the UFSAR Supplement (Appendix A of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of sytems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

Conclusions

The staff has reviewed the information provided in Section B1.6 of the LRA and the summary description of the fuel pool chemistry activities in Section A.1.6 of the UFSAR Supplement. On the basis of this review and the above evaluation, the staff found that there is reasonable assurance that the applicant has demonstrated that the effects of aging associated with the systems and components exposed to fuel pool water in the fuel pool cooling and cleanup system will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of agin for the systems and components discussed above as required by 10 CFR 54.21(d).

3.5.2.3 Conclusions

The staff has reviewed the information in Section 3.5.2 of the LRA as well as the applicable aging management program descriptions in Appendix B of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the components in the reactor building structure will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.5.3 Other Structures

3.5.3.1 Technical Information in the Application

The aging management review results for structures outside containment are presented in Tables 3.5-3 through 3.5-12 of the LRA. Each of these aging management review tables lists the (1) component groups, (2) intended functions, (3) environments, (4) materials of construction, (5) aging effects, and (6) aging management activities. The structural components listed in Tables 3.5-3 through 3.5-12 of the LRA are in the following structures:

- radwaste building and reactor auxiliary bay
- turbine building and main control room complex

- emergency cooling tower and reservoir
- station blackout structure and foundation
- yard structures
- stack
- nitrogen storage building
- diesel generator building
- circulating water pump structure
- recombiner building

A brief description of each of the above structures is provided in Section 2.4 of the LRA. In response to RAI 2.4.17-1, the applicant, by letter dated May 22, 2002, supplemented its LRA to include additional station-blackout-related SSCs that should be included within the scope of license renewal and subject to an AMR. The materials of construction are concrete, masonry block, steel, carbon and galvanized carbon, cast iron, aluminum, and gravel and sand.

The components of the structures outside containment are exposed to sheltered, outdoor, raw water, and buried environments.

3.5.3.1.1 Aging Effects

Tables 3.5-3 through 3.5-12 of the LRA and Table 2 of the response to RAI 2.4.17-1 identify the following applicable aging effects for components in structures outside the reactor building and containment:

- loss of material of carbon steel components in an outdoor environment
- change in material properties for reinforced concrete walls in a raw water outdoor environment
- cracking, loss of material, and change in material properties for concrete foundation, walls, slabs, and precast panels of station blackout structures in outdoor and sheltered environments
- cracking, loss of material, and change in material properties for masonry block walls in station blackout structures
- loss of material for galvanized carbon steel in station blackout structures in an outdoor environment

3.5.3.1.2 Aging Management Programs

Tables 3.5-3 through 3.5-12 of the LRA credit only the Maintenance Rule Structural Monitoring Program with managing the aging effects for the components in structures outside the reactor building and containment. Table 2 of the response to RAI 2.4.17-1 credits the Maintenance Rule Structural Monitoring Program with managing the aging effects for components in station blackout structures. A description of the Maintenance Rule Structural Monitoring Program is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components in structures outside containment will be adequately managed by this AMP such that there is reasonable assurance that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.5.3.2 Staff Evaluation

In addition to Section 3.5 of the LRA, the staff reviewed the pertinent information provided in Section 2.4, "Scoping and Screening Results: Structures and Component Supports," and the applicable aging management program descriptions provided in Appendix B of the LRA to determine whether the aging effects for the components in structures outside the reactor building and containment have been properly identified and will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

This section of this SER provides the staff's evaluation of the applicant's aging management review for the aging effects and the applicant's programs credited for the aging management of the components in structures outside the reactor building and containment at each Peach Bottom unit. The staff's evaluation includes a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the applicability of the aging management programs that are credited for managing the identified aging effects for components in structures outside the reactor building and containment.

3.5.3.2.1 Aging Effects

Concrete and Masonry Block walls: Tables 3.5-3 through 3.5-12 of the LRA identify change in material properties as an applicable aging effect for the reinforced concrete walls of the emergency cooling tower and reservoir. For other concrete components in outdoor, sheltered, or buried environments, Table 3.5-3 through 3.5-12 do not identify any applicable aging effects. Table 2 of the response to RAI 2.4.17-1 identifies cracking, loss of material, and change in material properties as aging effects for concrete foundations, walls, slabs, and precast panels of station blackout structures in outdoor and sheltered environments.

As noted above in Section 3.5.1.2.1 of this SER, the staff considers loss of material, cracking, and change in material properties to be both plausible and applicable aging effects for all concrete components, including masonry block walls, in all of the environments listed by the applicant. The NRC staff position regarding the aging management of in-scope concrete structures and components (SCs) is that they need to be periodically inspected in order to adequately monitor their performance or condition in a manner that allows for the timely identification and correction of degraded conditions. In RAI 3.5-1, the staff requested further information regarding the applicant's determination that management of concrete aging is not required. In response to RAI 3.5-1, the applicant stated that it disagrees with the staff's position regarding the aging management of concrete structures; however, the applicant has decided that it will manage concrete and masonry block wall aging during the period of extended operation. The applicant specifically stated that it will monitor concrete and masonry block wall structures for loss of material, cracking, and change in material properties through the Maintenance Rule Structural Monitoring Program. Since this commitment from the applicant covers the outdoor and sheltered concrete components in structures outside the reactor building, this response is considered to be acceptable to the staff. RAI 3.5-1 is considered closed with respect to the concrete components in structures outside the reactor building.

For the buried concrete components in structures outside the reactor building, the staff has determined that aging management is unnecessary if applicants are able to show that the below-grade soil/groundwater environment is nonaggressive. In response to RAI 3.5-1, the applicant provided water chemistry results that show that the Peach Bottom soil/groundwater environment is nonaggressive (pH = 7.2, sulfates = 38 ppm, and chlorides = 24 ppm). Consequently, the applicant concluded that the aging management of below-grade concrete is not required. Since the groundwater chemistry at the Peach Bottom site is well above the limit for pH (5.5) and below the limits for sulfates (1500 ppm) and chlorides (500 ppm), the staff concurs with the applicant's conclusion that the groundwater is nonaggressive with respect to concrete. Therefore, below-grade concrete does not need to be managed by the applicant.

Steel: The applicant identified loss of material of carbon steel components in an outdoor environment as an applicable aging effect for steel components in structures outside the reactor building.

The staff concurs with the aging effects identified above by the applicant for carbon steel exposed to an outdoor environment. However, the staff noted in Part 2 of RAI 3.5-2, that no aging effects are identified in Tables 3.5-3 through 3.5-12 for the carbon steel components in sheltered environments. In response to Part 2 of RAI 3.5-2, the applicant stated that it disagrees with the staff's position that carbon steel components in a sheltered environment require aging management. However, in response to RAI 3.5-2, the applicant committed to monitor carbon steel components in a sheltered environment for loss of material. This commitment includes all of the carbon steel components in structures outside the reactor building exposed to a sheltered environment for which the applicant did not originally identify any aging effects. Accordingly, the staff considers the applicant's response to RAI 3.5-2 with respect to carbon steel components in sheltered environments to be adequate.

For carbon steel in a buried environment, the applicant stated in its response to RAI 3.5-2 that:

> The only carbon steel structural components in a buried environment, which are within the scope of license renewal, are foundation piles for the diesel generator building (Table 3.5-10). As discussed in the PBAPS Updated Final Safety Report (UFSAR) Section 12.2.5, the building is founded on steel H piles and concrete shear walls, which are supported on rock. Selection of steel piles is based on the results of foundation studies considering field explorations and laboratory tests. The piles are driven to refusal and designed for a maximum load of 60 tons per pile. They support only gravity loads while the shear walls support lateral loads.
>
> The piles were driven into the reclaimed area of Conowingo Pond or in the backfilled areas where the rocks was excavated during plant construction. According to EPRI TR-103842, "Class I Structures License Renewal Industry Report: Revision 1," and NUREG 1557, "Summary of Technical Information and Agreements form Nuclear Management and Resources Council Industry Reports Addressing License Renewal," steel piles driven in undisturbed soils have been unaffected by corrosion and those drive in disturbed soil experience minor to moderate corrosion to a small area of the metal. Thus, the loss of material aging effect, due to corrosion, is non-significant and will not impact the intended function of piles.

The applicant's response is consistent with the staff position stated in NUREG-1557 regarding steel piles and is based on industry operating experience. As such, the staff considers the applicant's response to be acceptable.

Galvanized carbon steel: the applicant listed that galvanized carbon steel used in sheltered and outdoor environments in Table 2 of its response to RAI 2.4.17-1 for structures and support components related to station blackout. The applicant identified loss of material as an aging effect for galvanized carbon steel in the outdoor environment and credited the Maintenance Rule Structural Monitoring Program with managing the aging effect. The applicant identified no aging effect for galvanized carbon steel in the sheltered environment. The staff considers the applicant's response to be acceptable.

Cast Iron: Table 3.5-11 of the LRA does not identify any aging effects for the cast iron/carbon steel sluice gates of the circulating water pump structure, which are exposed to a raw water sheltered environment. In RAI 3.5-3, the staff requested further information concerning the applicant's AMR for the cast iron/carbon steel sluice gates of the circulating water pump structure. In response, the applicant committed to monitor loss of material of the sluice gates using the Outdoor, Buried, and Submerged Component Inspection Activities. The applicant's response to RAI 3.5-3 is acceptable to the staff.

Aluminum: Table 2 of the applicant's response to RAI 2.4.17-1 for structures and support components related to station blackout structures lists aluminum used for supporting members, sidings, electrical and instrumentation enclosures, and raceways. The applicant states that there are no aging effects for aluminum and therefore no aging management activities are required for aluminum materials. This is consistent with industry experience and the staff accepts the applicant's assessment.

3.5.3.2.2 Aging Management Programs

Tables 3.5-3 through 3.5-12 of the LRA credit only the Maintenance Rule Structural Monitoring Program with managing the aging effects for the components in structures outside the reactor building and containment. However, in response to RAI 3.5-3, the applicant committed to monitor loss of material of the cast iron/carbon steel sluice gates using the Outdoor, Buried, and Submerged Component Inspection Activities. Both the Maintenance Rule Structural Monitoring Program and the Outdoor, Buried, and Submerged Component Inspection Activities are credited with managing the aging of several components in several different structures and systems and are, therefore, considered common aging management programs. The staff review of the common aging management programs is in Section 3.0 of this SER.

3.5.3.3 Conclusions

The staff has reviewed the information in Sections 3.5.3 through 3.5.12 of the LRA as well as the applicable aging management program descriptions in Appendix B of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the components in structures outside the reactor building and containment will be adequately managed so that there is reasonable assurance that these components will perform their intended functions in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.5.4 Component Supports

3.5.4.1 Technical Information in the Application

The aging management review results for component supports are presented in Table 3.5-13 of the LRA. Table 3.5-13 of the LRA identifies the component support groups, intended functions, environments, materials of construction, aging effects, and (6) aging management activities.

The component groups for the component supports, as listed in Table 3.5-13 of the LRA, are support members, anchors, and grout.

Section 2.4.13 of the LRA states that the support member component group includes supports for piping and components, HVAC ducts, conduits, cable trays, instrumentation tubing trays, electrical junction and terminal boxes, electrical and I&C devices, instrument tubing, and supports for major equipment, including pumps, transformers, and HVAC fans and filters.

The anchor component group is the part of the component support assembly used to attach electrical panels, cabinets, racks, switchgears, enclosures for electrical and instrumentation equipment, pipe hangers, pumps, transformers, and HVAC fans and filters to other components or structures. Welds are used for steel attachments, and undercut anchors, expansion anchors, cast-in-place anchors, and grouted-in anchors are used for concrete attachments.

The grout component group includes grouted support pads and grouted base plates. Grout is used for constructing equipment pads and for filing and leveling equipment bases them to their respective foundations.

The materials of construction for the component supports which are subject to aging management review are carbon steel, stainless steel, alloy steel, galvanized steel, aluminum, bronze, graphite, and grout.

The component supports are exposed to internal (sheltered), outdoor, raw water, and torus water environments.

3.5.4.1.1 Aging Effects

Table 3.5-13 of the LRA identifies the following applicable aging effects for the component supports:

- loss of material for the emergency cooling water carbon steel anchors and support members exposed to an outdoor environment
- loss of material for carbon, alloy, and stainless steel support members exposed to a raw or torus water environment
- cracking of stainless steel support members exposed to torus water

3.5.4.1.2 Aging Management Programs

Table 3.5-13 of the LRA credits the following aging management programs with managing the aging effects for the component supports:

- ISI Program
- Torus Water Chemistry
- Maintenance Rule Structural Monitoring Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the component supports will be adequately managed by these aging management programs such that there is reasonable assurance that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.5.4.2 Staff Evaluation

In addition to Section 3.5 of the LRA, the staff reviewed the pertinent information provided in Section 2.4, "Scoping and Screening Results: Structures and Component Supports" and the applicable aging management program descriptions provided in Appendix B of the LRA to determine whether the aging effects for the component supports have been properly identified and will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

This section of this SER provides the staff's evaluation of the applicant's aging management review for aging effects and the applicant's programs credited for the aging management of the component supports at Peach Bottom. The staff's evaluation includes a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the applicability of the aging management programs that are credited for managing the identified aging effects for the component supports.

3.5.4.2.1 Aging Effects

Steel: The applicant identified loss of material for carbon steel component supports exposed to outdoor, raw water, and torus water environments. The applicant also identified loss of material for alloy and stainless steel components exposed to raw water and torus water environments. In addition, the applicant identified cracking as an aging effect for stainless steel support members exposed to torus water.

The staff concurs with each of the above aging effects that were identified for steel component supports. However, the staff also considers loss of material to be an applicable aging effect for carbon steel component supports in sheltered environments. As such, in RAI 3.5-2, the staff requested that the applicant justify its AMR results, which did not identify any aging effects, for carbon steel components in sheltered environments. In response to RAI 3.5-2, the applicant stated that it will use the Maintenance Rule Structural Monitoring Program to manage loss of material for carbon steel component supports in sheltered environments. These additional components, whose aging effects will now be managed during the period of extended operation, are carbon steel anchors and support members. Since the applicant committed to manage loss of material for carbon steel component supports in sheltered environments, the staff considers RAI 3.5-2 closed.

Grout: Grout is used in the construction of equipment pads, and for filing leveling equipment bases and setting them to their respective foundations. The applicant did not identify any applicable aging effects for grout and as a result, the staff requested in RAI 3.5-3 further information regarding this determination. In response, the applicant stated:

> As in concrete components, PBAPS AMRs did not identify any aging effects for grout that will result in loss of intended function. As a result, we concluded that an aging management activity is not required. However, considering the staff's position on concrete, we will monitor accessible grout for cracking using the PBAPS Maintenance Rule Structural Monitoring Program.

The applicant's commitment to monitor grout for cracking is acceptable to the staff. Thus, RAI 3.5-3, with respect to grout, is considered closed.

Bronze/Graphite: Table 3.5-13 of the LRA does not identify any aging effects for the bronze/graphite Lubrite plates used as component supports. In Part 1 of RAI 3.5-3, the staff requested further information regarding the applicant's AMR for Lubrite plates. In response, the applicant stated:

> Lubrite is the trade name for a low-friction lubricant material used in applications where relative motion (sliding) is desired. At PBAPS, Lubrite plates are incorporated in the design of limited component supports to reduce or release horizontal loads due to temperature transients and SRV discharges.
>
> PBAPS AMRs determined that there are no known aging effects for the Lubrite material that would lead to a loss of intended function. As explained by previous applicants and concurred by the staff, Lubrite resists deformation, has a low coefficient of friction, resists softening at elevated temperatures, absorbs grit and abrasive particles, is not susceptible to corrosion, withstands high intensities of radiation, and will not score or mar. In addition, lubrite products are solid, permanent, completely self-lubricating, and require no maintenance as documented in NUREG-1759, "Safety Evaluation Report Related to the License Renewal of Turkey Point Nuclear Plant, Units 3 and 4." A search of PBAPS and industry operating experience found no reported instances of lubrite plate degradation or failure to perform their intended function. On this basis, Exelon maintains that lubrite plates require no aging management.

The staff concurs with the applicant's response to RAI 3.5-3 with respect to the need for managing the aging of lubrite plates. The applicant's AMR of lubrite material is consistent with industry experience. The staff considers Part 1 of RAI 3.5-3 to be closed.

Aluminum: Aluminum is used for some of the support members. The applicant does not identify any aging effects for aluminum because the aluminum support members are located in a sheltered environment. Thus no AMR is required for aluminum. The staff concurs with this finding.

3.5.4.2.2 Aging Management Programs

Table 3.5-13 of the LRA credits the following aging management programs with managing the identified aging effects for component supports:

- Maintenance Rule Structural Monitoring Program
- ISI Program
- Torus Water Chemistry

Each of the above aging management programs are credited with managing the aging of several components in various different structures and systems. These programs are, therefore, considered common aging management programs. The staff review of the common aging management programs is in Section 3.0 of this SER.

3.5.4.3 Conclusions

The staff has reviewed the information in Section 3.5 of the LRA as well as the applicable aging management program descriptions in Appendix B of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the component supports will be adequately managed so that there is reasonable assurance that these supports will perform their intended functions in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.5.5 Hazard Barriers and Elastomers

3.5.5.1 Technical Information in the Application

The aging management review results for the hazard barriers and elastomers are presented in Table 3.5-14 of the LRA. Table 3.5-14 of the LRA identifies the components in the hazard barrier and elastomer component group as well as the component (1) functions, (2) materials, (3) environments, (4) aging effects, and (5) aging management programs.

The materials of construction of the hazard barriers and elastomers are

- carbon steel
- silicone
- rubber
- neoprene
- boot fabric (BISCO)
- fire stop putty
- grout cement
- alumina silica
- resin
- adhesive

- subliming compound
- cementitious fireproofing
- polysulfide sealant

The hazard barriers and elastomers listed in Table 3.5-14 of the LRA are exposed to sheltered and outdoor environments.

3.5.5.1.1 Aging Effects

Table 3.5-14 of the LRA identifies the following applicable aging effects for the hazard barriers and elastomers:

- cracking
- delamination and separation
- change in material properties
- loss of material
- loss of sealing

3.5.5.1.2 Aging Management Programs

Table 3.5-14 of the LRA credits the following aging management programs with managing the aging effects for the hazard barriers and elastomers:

- Door Inspection Activities
- Fire Protection Activities
- Maintenance Rule Structural Monitoring Program
- Primary Containment ISI Program

A description of these aging management programs and activities is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the hazard barriers and elastomers will be adequately managed by these aging management programs such that there is reasonable assurance that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.5.5.2 Staff Evaluation

In addition to Section 3.5 of the LRA, the staff reviewed the pertinent information provided in Section 2.4, “Scoping and Screening Results: Structures and Component Supports” and the applicable aging management program descriptions provided in Appendix B of the LRA to determine whether the aging effects for the hazard barriers and elastomers have been properly identified and will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

This section of this SER provides the staff’s evaluation of the applicant’s aging management review for aging effects and the applicant’s programs credited for the aging management of the hazard barriers and elastomers at Peach Bottom. The staff’s evaluation includes a review of the aging effects considered and the basis for the applicant’s elimination of certain aging effects. In addition, the staff has evaluated the applicability of the aging management programs that are credited for managing the identified aging effects for the hazard barriers and elastomers.

3.5.5.2.1 Aging Effects

Elastomers: The applicant identified cracking, change in material properties, separation and delamination, and loss of sealing as applicable aging effects for the elastomers listed in Table 3.5-14 of the LRA. However, for the neoprene reactor building blowout panel seals and the silicone reactor building metal siding gap seals, the applicant did not identify any applicable aging effects. Therefore, in RAI 3.5-3, the staff requested that the applicant justify its AMR results for these two components. Regarding the neoprene reactor building blowout panel seals, the applicant stated:

> PBAPS AMRs determined that the neoprene seals are susceptible to change in material properties and cracking, due to thermal exposure and ionizing radiation, only if the operating temperature exceeds 160° F or the radiation exceeds 10^6 rads. The seals for the reactor building blowout panels are located in an environment where the temperature does not exceed 112° F and the maximum total integrated gamma dose is less than 3.5×10^5 rads for 60 years. On this basis, the AMRs concluded that change in material properties and cracking aging effects are not applicable to the reactor building blowout panel seals.

Regarding the silicone reactor building metal siding gap seals, the applicant stated:

> The silicone seal specified for the reactor building metal siding is either Dow Corning product No. 732 or 790. According to the Dow Corning materials group, the products are capable of sustaining long-term temperatures greater than 158° F. The lowest threshold radiation dose for silicone is 10^6 rads. The silicone seals for the reactor building metal siding are located in an environment where the temperature does not exceed 112° F and the maximum total integrated gamma dose is less than 3.5×10^6 rads for 60 years. On this basis, PBAPS AMRs concluded that change in material properties and cracking aging effects are not applicable to the reactor building metal siding silicone seals.

Since the temperature and radiation limits for the neoprene blowout panel seals and the silicone metal siding gap seals are well above the actual values for the reactor building, the staff concurs with the applicant’s determination that there are no applicable aging effects for these two components. The staff finds that the applicant has properly identified the applicable aging effects for the elastomers.

Fire Proofing: For the fire proofing wraps, the applicant identified change in material properties and loss of material as applicable aging effects. The staff finds that the applicant has properly identified the applicable aging effects for the fire proofing wraps.

Steel: For the carbon steel hazard barrier doors, the applicant identified loss of material as an applicable aging effect for the doors that are exposed to an outdoor environment. For the carbon steel hazard barrier doors in a sheltered environment, the applicant did not identify loss of material as an applicable aging effect. In RAI 3.5-2, the staff requested that the applicant justify its determination that loss of material is not an applicable aging effect for carbon steel hazard barrier doors in a sheltered environment. In response to RAI 3.5-2, the applicant committed to monitor loss of material due to corrosion for the carbon steel hazard barrier doors in a sheltered environment. The staff finds the applicant's commitment to be acceptable.

3.5.5.2.2 Aging Management Programs

Table 3.5-14 of the LRA credits the following aging management programs with managing the identified aging effects for the hazard barriers and elastomers:

- Door Inspection Activities
- Fire Protection Activities
- Maintenance Rule Structural Monitoring Program
- Primary Containment ISI Program

Each of the above programs is credited with managing the aging of several components in various different structures and systems and are, therefore, considered common aging management programs. The staff review of the common aging management programs is in Section 3.0 of this SER.

3.5.5.3 Conclusions

The staff has reviewed the information in Section 3.5 of the LRA as well as the applicable aging management program descriptions in Appendix B of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the hazard barriers and elastomers will be adequately managed so that there is reasonable assurance that these components will perform their intended functions in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.5.6 Miscellaneous Steel

3.5.6.1 Technical Information in the Application

The aging management review results for miscellaneous steel components are presented in Table 3.5-15 of the LRA. Table 3.5-15 of the LRA identifies the component (1) groups, (2) intended functions, (3) environments, (4) materials of construction, (5) aging effects, and (6) aging management programs.

Section 2.4.15 of the LRA states that the miscellaneous steel group includes platforms, grating, stairs, ladders, steel curbs, handrails, kick plates, decking, instrument tubing trays, and manhole covers. Each of the miscellaneous steel components listed in Table 3.5-15 of the LRA is constructed of carbon steel and exposed to either a sheltered or an outdoor environment.

3.5.6.1.1 Aging Effects

Table 3.5-15 of the LRA does not identify any applicable aging effects for the miscellaneous steel components.

3.5.6.1.2 Aging Management Programs

Since there are no aging effects identified for the miscellaneous carbon steel components in Table 3.5-15 of the LRA, the applicant does not credit any aging management programs.

3.5.6.2 Staff Evaluation

In addition to Section 3.5 of the LRA, the staff reviewed the pertinent information provided in Section 2.4, "Scoping and Screening Results: Structures and Component Supports" and the applicable aging management program descriptions provided in Appendix B of the LRA to determine whether the aging effects for the miscellaneous steel components have been properly identified and will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

This section of this SER provides the staff's evaluation of the applicant's aging management review for aging effects of the miscellaneous steel components at Peach Bottom. The staff's evaluation includes a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects.

3.5.6.2.1 Aging Effects

For the miscellaneous steel components identified in Table 3.5-15 of the LRA, the applicant did not identify any applicable aging effects. Since the miscellaneous steel components are constructed of carbon steel and exposed to both sheltered and outdoor environments, the staff requested in RAI 3.5-2 that the applicant justify its AMR for these components. In response to RAI 3.5-2, the applicant stated that it will monitor the miscellaneous carbon steel components exposed to sheltered environments for loss of material using its Maintenance Rule Structural Monitoring Program. The following miscellaneous steel components listed in Table 3.5-15 of the LRA will now be monitored by the Maintenance Rule Structural Monitoring Program:

- platforms
- grating
- stairs
- ladders
- steel curbs
- handrails
- kick plates
- instrument tubing trays

The staff concurs with the applicant's commitment to manage the aging of the miscellaneous carbon steel components listed in Table 3.5-15 of the LRA.

For the manhole covers, which are the only carbon steel components listed in Table 3.5-15 of the LRA that are exposed to an outdoor environment, the applicant stated in response to RAI 3.5-2:

> Manhole covers are heavy-duty type gray iron castings, manufactured by NEENAH Foundry Company to ASTM A48.74, AASHTO M105-621, and Federal QQI-625c standards. The higher silicon content and the presence of graphite flakes contained in the ferrous materials for these castings provide natural corrosion resistance. The covers have been widely used by utilities and highway

> departments in extreme/severe outdoor environments for several decades. Experience with the covers has shown that loss of material due to corrosion is non-significant and will not impact the intended function of the covers. As a result, aging management of manhole covers is not required.

The staff concurs with the applicant's determination that the manhole covers are rugged, heavy-duty materials that have withstood severe environments with little degradation for long periods of time. Therefore, aging management of the manhole covers is unnecessary.

3.5.6.2.2 Aging Management Programs

Table 3.5-15 of the LRA does not list any aging management programs for the miscellaneous steel components; however, in response to RAI 3.5-2 the applicant has committed to using the Maintenance Rule Structural Monitoring Program to manage the aging effects for the miscellaneous steel components in sheltered environments. The Maintenance Rule Structural Monitoring Program is credited with managing the aging of several components in various different structures and systems and is, therefore, considered a common aging management program. The staff review of the common aging management programs is in Section 3.0 of this SER.

3.5.6.3 Conclusions

The staff has reviewed the information in Section 3.5 of the LRA as well as the applicable aging management program descriptions in Appendix B of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the miscellaneous steel components will be adequately managed so that there is reasonable assurance that these components will perform their intended functions in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.5.7 Electrical and Instrumentation Enclosures and Raceways

3.5.7.1 Technical Information in the Application

The aging management review results for electrical and instrumentation enclosure and raceway component group are presented in Table 3.5-16 of the LRA. Table 3.5-16 of the LRA identifies the component (1) groups, (2) intended functions, (3) environments, (4) materials of construction, (5) aging effects, and (6) aging management programs.

Section 2.4.16 of the LRA states that the electrical and instrumentation enclosures and raceways group includes cable trays, cable tray covers, drip shields, rigid and flexible electrical conduits and fittings, wireway gutters, panels, cabinets, and boxes.

The materials of construction for the electrical and instrumentation enclosures and raceways are carbon steel, aluminum, and galvanized carbon steel.

The electrical and instrumentation enclosures and raceways are exposed to both sheltered and outdoor environments.

3.5.7.1.1 Aging Effects

Table 3.5-16 of the LRA does not identify any applicable aging effects for the electrical and instrumentation enclosures and raceways.

3.5.7.1.2 Aging Management Programs

Since no aging effects are identified in Table 3.5-16 of the LRA, no aging management programs are listed for the electrical and instrumentation enclosures and raceways.

3.5.7.2 Staff Evaluation

In addition to Section 3.5 of the LRA, the staff reviewed the pertinent information provided in Section 2.4, "Scoping and Screening Results: Structures and Component Supports" and the applicable aging management program descriptions provided in Appendix B of the LRA to determine whether the aging effects for the electrical and instrumentation enclosures and raceways have been properly identified and will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

This section of this SER provides the staff's evaluation of the applicant's aging management review for aging effects of the electrical and instrumentation enclosures and raceways at Peach Bottom. The staff's evaluation includes a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects.

3.5.7.2.1 Aging Effects

Steel: Table 3.5-16 of the LRA does not list any aging effects for the electrical and instrumentation enclosures and raceways. Since carbon steel is listed as one of the materials of construction for the electrical and instrumentation enclosures and raceways, the staff requested in RAI 3.5-2 further information regarding the applicant's AMR for these components. In response the applicant stated:

> Carbon steel components in this commodity group are constructed of factory baked painted steel or galvanized castings and sheet metal. The components are located in a sheltered environment, which is nonaggressive and does not contain high moisture. In some locations, such as the main control room, and the emergency switchgear room, the environment is air conditioned and controlled. As documented in NUREG/CR-4715, "Aging Assessment of Relays and Circuit Breakers and System Interactions," the components do not have a tendency to age with time.
>
> Industry operating experience with metal housing systems, in similar environments, indicates that they have performed with failure to the present as documented in SAND93-7069, "Aging Management Guideline for Commercial Nuclear Power Plants-Motor Control Centers," and SAND93-7027, "Aging Management Guideline for Commercial Nuclear Power Plants-Electrical Switchgear." PBAPS operating experience is consistent with the industry operating experience. As a result, our position remains that loss of material, due to corrosion, will not impact the intended function of components listed in Table 3.5-16. Thus no aging management is required.

The staff concurs with the applicant's AMR for the electrical and instrumentation enclosures and raceways. Since these components are constructed of factory-baked painted steel or galvanized castings and sheet metal and in controlled environments, aging degradation of the electrical and instrumentation enclosures and raceways should be minimal. Therefore, the staff considers RAI 3.5-2 to be closed with respect to the electrical and instrumentation enclosures and raceways.

Aluminum: Aluminum is used for some of the electrical and instrumentation enclosures and raceways. The applicant states that there are no aging effects for aluminum and therefore no aging management activities are required for aluminum materials. This is consistent with industry experience and the staff accepts the applicant's assessment.

3.5.7.2.2 Aging Management Programs

Since no aging effects are identified in Table 3.5-16 of the LRA, no aging management programs are listed for the electrical and instrumentation enclosures and raceways.

3.5.7.3 Conclusions

The staff has reviewed the information in Section 3.5 of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that there are no aging effects for the electrical and instrumentation enclosures and raceways.

3.5.8 Insulation

3.5.8.1 Technical Information in the Application

The aging management review results for the insulation commodity group are presented in Table 3.5-17 of the LRA. Table 3.5-17 of the LRA identifies the component (1) groups, (2) intended functions, (3) environments, (4) materials of construction, (5) aging effects, and (6) aging management programs.

Section 2.5.17 of the LRA states that the insulation commodity group includes all insulating materials within the scope of license renewal that are used in plant areas where temperature control is considered critical for system and component operation or where high room temperatures could impact environmental qualification. The plant areas that require temperature control are the interiors of drywell, the HPCI and RCIC pump rooms, and the outboard MSIV rooms. Outdoor piping and components also require heat tracing for freeze protection.

The insulation materials include stainless steel and aluminum mirror insulation and fiberglass blanket insulation with either stainless steel or aluminum jacketing. Other insulation materials are calcium silicate or fiberglass blankets covered by an aluminum jacket. Equipment insulation consists of either calcium silicate blocks or removable ceramic-fiber blankets.

Insulation at Peach Bottom is found in both sheltered and outdoor environments.

3.5.8.1.1 Aging Effects

Table 3.5-17 of the LRA identifies insulation degradation as an applicable aging effect for the aluminum insulation jacketing with stainless steel straps that is exposed to an outdoor environment.

3.5.8.1.2 Aging Management Programs

Table 3.5-17 of the LRA credits the Outdoor, Buried, and Submerged Component Inspection Activities with managing the aging effect insulation degradation. This aging management program is described in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the insulation will be adequately managed by the Outdoor, Buried, and Submerged Component Inspection Activities such that there is reasonable assurance that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.5.8.2 Staff Evaluation

In addition to Section 3.5 of the LRA, the staff reviewed the pertinent information provided in Section 2.4, "Scoping and Screening Results: Structures and Component Supports," and the applicable aging management program descriptions provided in Appendix B of the LRA to determine whether the aging effects for the insulation have been properly identified and will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

This section of this SER provides the staff's evaluation of the applicant's aging management review for aging effects and the applicant's program credited for the aging management of the insulation at Peach Bottom. The staff's evaluation includes a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the applicability of the aging management program that is credited for managing the identified aging effect for the insulation.

3.5.8.2.1 Aging Effects

Table 3.5-17 of the LRA identifies insulation degradation as an applicable aging effect for aluminum insulation with stainless steel strips that is exposed to an outdoor environment. For insulation in sheltered environments, the applicant did not identify any applicable aging effects.

The staff finds that the applicant's approach for evaluating the applicable aging effects for the insulation to be reasonable and acceptable. The staff concludes that the applicant has properly identified the aging effect for the insulation.

3.5.8.2.2 Aging Management Programs

Table 3.5-17 of the LRA credits the Outdoor, Buried, and Submerged Component Inspection Activities with managing insulation degradation. The Outdoor, Buried, and Submerged Component Inspection Activities are credited with managing the aging of several components in several different structures and systems and are, therefore, considered a common aging management program. The staff review of the common aging management programs is in Section 3.0 of this SER.

3.5.8.3 Conclusions

The staff has reviewed the information in Section 3.5 of the LRA as well as the applicable aging management program descriptions in Appendix B of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the insulation will be adequately managed so that there is reasonable assurance that this components will perform its intended function in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.6 Aging Management of Electrical and Instrumentation and Controls

The applicant described its AMR results for the Peach Bottom electrical/I&C components requiring AMR in Section 3.6 of the LRA. The applicant stated that Tables 3.6.1, 3.6.2, and 3.6.3 provided the results of the aging management reviews for the electrical commodities and station blackout system components within the scope of license renewal and that are subject to an aging management review. Because the commodities are not associated with one particular system but could be in any in-scope system, they were evaluated using a “spaces” approach.

The spaces evaluation was based on areas where bounding service environmental parameters were identified. For example, the temperature bounding service environmental parameter is the highest average service temperature present in the defined space, taking into account the ambient temperature (and ohmic heating where applicable). This bounding value is then compared to the 60-year limiting service temperature. The 60-year limiting service temperature is the temperature at which the insulation material experiences no aging effect which would cause the insulation material to lose its intended function for the period of extended operation.

The process used to perform an aging management review of a commodity or component group for a specific environmental stressor is as follows:

- Identify the component group materials of construction.

- Identify the aging effects for the component group when exposed to the environmental stressor.

- Determine the value of the bounding service environmental parameter to which the component groups in the area to be reviewed are exposed.

- Compare the aging characteristics of the identified materials in the bounding service environmental parameter against the 60-year limiting service environmental parameter, and determine if the component groups are able to maintain their intended function during the period of extended operation.

The staff reviewed this section of the application to determine whether the applicant has demonstrated that the effect of aging on the electrical/I&C components will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.6.1 Cables

3.6.1.1 Technical Information in the Application

In Section 2.5.1 of the LRA, the applicant stated that there are approximately 39,000 installed cables at PBAPS. Electrical cables were treated as a commodity group during the aging management review process. This group includes all documented cables within the scope of license renewal that are used for power, control, and instrumentation applications. The intended function of electrical cables is to provide electrical connections to specified sections of an electrical circuit to deliver voltage, current, or signals. Electrical cables are located in sheltered environment. Although EQ cables are reviewed as TLLAs, all documented cables, whether EQ or Non-EQ, were assumed to be in scope and to require aging management review.

The applicant indicated that cable insulation material groups for both safety-related and non-safety-related cables were assessed on the basis of common materials and their respective material aging characteristics.

The applicant used the plant database as the primary tool to identify cable insulation groups and to screen electrical cables for the cable aging management review. The database contains a cable code. The cable code identifies a unique cable size, application (power, control, or instrumentation), and insulation. Cable insulation groups and their applications were the determining factors in performing the assessment against bounding parameters.

The electrical cable aging management review for radiation and temperature utilized a plant “spaces” approach, whereby aging effects were identified and bounding environmental parameters were used to evaluate the identified aging effects with respect to component intended function.

3.6.1.1.1 Aging Effects

The applicant states that the stressors potentially affecting loss of material properties for cables at PBAPS are moisture, temperature, and radiation.

Moisture is of concern because of a phenomenon called “water treeing.” To be identified as being susceptible to aging effects caused by water treeing, a Non-EQ cable must be exposed to long-term standing water, be energized more than 25% of the time, carry medium voltage (4kV-13kV for PBAPS), and be constructed of insulation material containing a void or impurity (inclusion, flaw).

The industry and manufacturers recognized this issue in the late 70s. Improved formulations (more resistant to water treeing) have been available and used since 1980. PBAPS recognized this issue and initiated a cable replacement program in 1995 to replace “suspected” cables that met the water treeing criteria described above. No cable failures have occurred at PBAPS since the cable replacement program was initiated. The applicant concluded that moisture is not an aging effect requiring management at PBAPS.

The remaining stressors affecting loss of material properties of cable insulation at PBAPS are temperature and radiation. Applying the “spaces” approach to the identification of the temperature and radiation stressors was a primary focus for the aging management review of cables. Maintaining adequate dielectric properties of the cable insulation is essential for ensuring that the electrical cables perform their intended function.

A review of cable insulation aging effects from radiation was performed by comparing the lowest radiation cable insulation with the highest radiation area where cables that support components within the scope of license renewal may be present in the plant. The value used for the highest radiation area was obtained by multiplying the existing radiation design value by 1.5 to obtain the 60-year value and then adding the accident dose. All other cable insulation types were bounded by this analysis. No cables requiring aging management as a result of radiation effects were identified.

A review of cable insulation aging effects from temperature required a more detailed elimination process. Cable populations were grouped according to their common cable insulation material type and voltage application (power, control, or instrumentation). For each cable insulation material type, a 60-year limiting service temperature was established. This value was compared to the bounding cable service temperature to determine if it was below the 60-year limiting service temperature. Ohmic heating was considered for power cables and for control cables that are routed with power cables, where applicable to determine the bounding service temperature. A summary of each cable group review follows:

- <u>Computer Cable Groups</u>

  Computer cable groups are not in the scope of license renewal and were eliminated from the temperature review.

- <u>Fibre Optic & Bare Ground Cable Groups</u>

  Fibre optic cable insulation material is unaffected by thermal aging. Bare ground cables have no insulation and were determined not to be within the scope of license renewal.

- <u>Instrumentation Cable Groups</u>

  Instrumentation cable groups with cross-linked polyethylene (XLPE), polyethylene, cross-linked polyolefin (XLPO), hypalon, Teflon-based, and polypropylene insulation were determined to have 60-year limiting service temperature greater than the bounding ambient temperature of PBAPS. Two bounding ambient temperatures were determined: one bounding ambient temperature for containment and another bounding ambient temperature for all other plant areas.

- <u>XLPE Power & Control Cable Groups</u>

  XLPE insulated cable groups can operate continuously at their bounding service temperature for greater than 60-years. The 60-year limiting service temperature is greater than bounding ambient temperature and its associated ohmic heating temperature rise.

- <u>EPR Power & Control Cable Groups</u>

  EPR (ethylene polymer rubber) cable groups supplying loads not in the scope of license renewal were eliminated from review. The remaining EPR cable groups were determined to be routed in areas outside containment and have 60-year limiting service temperature greater than the bounding ambient temperature and its associated ohmic heating temperature rise.

- PE Power and Control Cable Groups

  The routing of PE (polyethylene) power and control cable groups was determined and local ambient temperature field measurements were conducted in bounding cases. The 60-year limiting service temperature for PE insulation groups was greater than the bounding ambient temperature and its associated ohmic heating temperature rise.

- PVC Cable Groups

  Poly-vinyl-chloride (PVC) cables groups and individual cables from the remaining PVC cable groups supplying loads not in the scope of license renewal were eliminated from review. The remaining PVC cables were reviewed to identify cables with 60-year limiting service temperatures greater than the bounding service temperature. Thirty cables relied upon for fire safe shutdown (FSSD) were determined to require aging management.

- Miscellaneous Cable Groups

  Miscellaneous cables groups not in the scope of license renewal loads were eliminated from review. Miscellaneous cable groups were also reviewed to eliminate cables with a 60-year limiting service temperature greater than the bounding ambient temperature. Individual cables within the remaining group were reviewed to identify cables within the scope of the environmental qualification aging management activity or cables supplying loads not within the scope of license renewal. None of the miscellaneous cables were identified as requiring management.

3.6.1.1.2 Aging Management Program

Table 3.6-1 of the LRA provides the aging management review results for cables. In this table, no aging management activity is identified except for PVC insulated fire safe shutdown cables. The applicant states that a cable replacement program was initiated in 1995 to replace “suspected” cables subject to the water-treeing. No cable failures have occurred at PBAPS since the cable replacement program was initiated. Therefore, moisture is not an aging effect requiring management at PBAPS. The applicant also states that the maximum operating doses of insulation material (1.5 times the existing radiation design value plus the accident dose) will not exceed the 60-year service limiting radiation dose. The maximum operating temperature of insulation material will also not exceed the maximum temperature for 60-year life. The applicant concludes that no aging management programs are required for cables due to heat or radiation.

The fire safe shutdown (FSSD) inspection activity is a new aging management program. The applicant reviewed the PVC cable groups and determined that 30 cables relied upon for fire safe shutdown require aging management. These cables have a 60-year service temperature greater than the bounding service temperature. These cables are located in the drywell and are all MSRV discharge line thermocouple wires. The inspection will manage change in material properties of the PVC insulation.

3.6.1.2 Staff Evaluation

The staff evaluated the information on aging management presented in LRA, Sections 2.5.1and 3.6 and in the applicant's response to the staff RAIs dated January 2 and April 29, 2002. The staff evaluation was conducted to determine if there is a reasonable assurance that the applicant has demonstrated that the effects of aging will be adequately managed, consistent with its CLB throughout the period of extended operation, in accordance with 10 CFR 54.21(a)(3). This section of this SER provides the staff's evaluation of the applicant's aging management review of aging effects and the applicant's program credited for the aging management of insulated cables at Peach Bottom. The staff's evaluation includes a review of the aging effects considered. In addition, the staff has evaluated the applicability for the aging management program that is credited for managing the identified aging effects for the insulated cables.

3.6.1.2.1 Aging Effects

A cable replacement program was initiated in 1995 to replace "suspected" cables that met the water treeing criteria. Water treeing is moisture intrusion to the cable insulation that results in a decrease in the dielectric strength of the conductor insulation, which in turn results in cable failure. The applicant concluded that moisture is not an aging affect requiring management at PBAPS. It was not clear to the staff why moisture has not been an aging effect requiring management at Peach Bottom since the cables were replaced. The staff requested that the applicant provide details about the cable replacement program and explain why moisture is not an aging effect requiring management for these new cables. In a response dated January 2, 2002, the applicant stated that water treeing affects cable insulation materials having an ethylene polymer base. Water treeing has been shown to occur predominately in cables with cross-linked polyethylene (XLPE) insulation. The cable manufacturers and the utility industry recognized the water treeing phenomenon in the 1970s and improved formulations (resistant to water treeing) of XLPE cable insulation used in underground applications since 1980.

PBAPS experienced a series of nonsafety cable failures between 1984 and 1991, when XLPE insulated 5kV and 15kV cables failed with no cause initially identified. Analyses attributed one failure, in 1991, to water treeing. Further analysis on the other cable samples was conducted, and evidence of water trees was found in six cases. The trees were found to be extensive in some cases. A cable replacement program was initiated at PBAPS in 1995 and completed in 1999 on "suspected" cables subjected to the collective conditions listed above. The replacement cable was ethylene propylene rubber (EPR) insulated cable, pink in color, which has a low level of crystallinity with a poly-vinyl-chloride (PVC) jacket, suitable for use in wet or dry location in conduit, underground duct system, or direct buried, or aerial installations. The cables are rated for a minimum of 90 °C for normal operation, 130 °C for emergency loading operation, and 250 °C for short circuit conditions. The basic construction of the cable is either single-conductor Class B stranded base copper or aluminum, with extruded semiconducting strand screen, EPR insulation, extruded semiconducting insulation screen, bare copper shielding tape, and PVC jacket. A review of the PBAPS operating history has determined that no additional cable failures, caused by the effects of water treeing, have occurred at PBAPS since the cable replacement program was completed.

The applicant also provided a summary of a paper, "An assessment of Field Aged 15kV and 35kV Ehtylene Propylene Rubber Insulation Cables," published in the 1994 T&D Conference

Proceedings in support of not having an aging management program for medium-voltage cables exposed to an adverse localized environment caused by moisture-produced water trees and voltage stress. It was not clear to the staff that the information in the paper is adequate for not having an AMP for medium-voltage cables exposed to an adverse localized environment caused by moisture-produced water trees and voltage stress. The staff requested the applicant to provide an aging management program for accessible and inaccessible medium-voltage (2kV-15kV) cables (e.g., installed in conduit or direct buried) exposed to an adverse localized environmental caused by moisture-produced water trees and voltage stress. In a response dated April 29, 2002, the applicant reiterated its view and stated that PBAPS elected to replace cables suspected to be susceptible to water treeing. Since the replacement cables were suitable for use in wet environment, the applicant believes that moisture is not an aging effect requiring management at PBAPS.

The applicant also stated that a review of the manufacturer's Product Data Sheet, Section 2, Sheet 9, for Okoguard-Okoseal Type MV-90 cable. The paragraph under the heading Applications states: "Type MV cables may be installed in <u>wet or dry</u> environments, indoors or outdoors (exposed to sunlight), in any raceway or underground duct." The paragraph headed "Product Features" additionally states that "triple tandem extruded, all EPR system, Okoguard cables meet or exceed all recognized industry standards (UL, AEIC, NEMA/ICEA, IEEE), moisture resistant, exceptional resistance to water treeing." The above information is repeated in the manufacturer's specification, and provides a warrantee for cable failure due to defects in material or workmanship for 40 years.

The applicant believed that choosing cable capable of being installed in a wet location removes the potential for water treeing to occur. In addition, the applicant stated that a review of the PBAPS operating history has discovered no additional cable failures caused by the effects of water treeing have occurred at PBAPS since the cable replacement program was completed.

The staff acknowledges that the EPR-insulated replacement cable is more resistant to water-treeing. However, the staff still does not accept the applicant's positions that moisture is not an aging effect requiring aging management for these cables. The staff believes that the discussion and conclusion of the paper, "Assessment of Field Aged 15kV and 35kV Ethylene Propylene Rubber Insulated Cables," do not support the applicant's position that moisture is not an aging effect requiring management at PBAPS. For example, the paper concludes that aging of the EPR-insulated cables can be characterized by an increase in moisture content, growth of water trees, drop in insulation elongation, increase in dissipation factor, and decrease in AC and impulse voltage breakdown strength. Further, the data for water trees, elongation, dissipation factor, and AC and impulse strength indicate that EPR insulated cable deterioration appears to result from moisture permeating the insulation of the cable. Therefore, the applicant has not provided a sufficient technical justification for not requiring an aging management program for inaccessible medium-voltage cables and has not proposed to prevent such cables from being exposed to significant moisture, such as inspecting for water collection in cable manholes and conduit and draining water, as needed. **This is part of Open Item 3.6.1.2.1-1.** The additional part of this open item is discussed in Section 3.6.3.2.1 of this SER.

For accessible Non-EQ cables installed in adverse localized environments due to heat or radiation, in Section 2.5.1 of the LRA, the applicant states that the maximum operating doses of insulation material (1.5 times the existing radiation design value plus the accident dose) will not exceed the 60 year-service limiting radiation dose. The applicant also states that the maximum operating temperature of insulation material will not exceed the maximum temperature for 60-year life. Therefore, it concludes that no aging management is required for aging effects due heat or radiation. Additionally, on January 2, 2002, the applicant stated that a plant walk down was conducted outside containment (i.e., excluding the drywell and steam tunnel) to identify any adverse localized equipment environments. It was concluded that only the drywell PVC cables credited for fire safe shutdown required an aging management activity. The staff finds that this conclusion is not consistent with the aging management program and activities for electrical cables and connections exposed to adverse localized environments caused by heat or radiation, because conductor insulation material used in cables may degrade more rapidly than expected.

The radiation levels most equipment experience during normal service have little degrading effect on most materials. However, some localized areas may experience higher-than-expected radiation conditions. Areas prone to elevated radiation levels include areas near primary reactor coolant system piping or the reactor-pressure-vessel; areas near waste processing systems and equipment (e.g., gaseous waste system, reactor purification system, reactor water cleanup system, and spent fuel pool cooling and cleanup system); and areas subject to radiation streaming. The most common adverse localized equipment are those created by elevated temperature. Elevated temperature can cause equipment environments to age prematurely, particularly equipment containing organic materials and lubricants. The effect of elevated temperature can be quite dramatic. Areas that are prone to high temperature include areas with high temperature process fluid piping and vessels, areas with equipment that operate at high-temperature, and areas with limited ventilation. Industry operating experience indicates that aging of cables requires aging management. In a letter to the applicant dated January 23, 2002 (RAI Number 3.6-1), the staff requested the applicant to provide (1) an aging management program for accessible and inaccessible electrical cable and connections exposed to an adverse localized environment caused by heat and radiation and (2) an aging management program for accessible and inaccessible electrical cables used in instrumentation circuits that are sensitive to reduction in conductor insulation resistance and exposed to an adverse localized environment caused by heat or radiation.

In response to the staff’s request, in a letter dated April 29, 2002, the applicant states that with regard to an aging management program for accessible and inaccessible electrical cables and connections exposed to an adverse localized environment caused by heat or radiation, it understands that the staff, in the RAI, is requesting a program similar to GALL Report Program X1.E1, “Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.”   Based on the guidance in EPRI TR-109619, “Guideline for the Management of Adverse Localized Equipment Environments,” it has been found that plant operating experience (i.e., a study of plant problem reports) and visual inspection are two methods of identifying adverse localized equipment environments (or hot spots). As discussed in its letter dated January 2, 2002, a plant walkdown was performed outside containment (i.e., not in the drywell or steam tunnel). The purpose of the walkdown was to take the local temperature data and look for adverse localized equipment environments. A digital thermometer and an infrared camera were used. No adverse localized equipment (e.g., cables within 3 feet of hot process piping) were identified during the plant walkdown. Additionally, review of PBAPS plant operating experience did not identify any Non-EQ cable and connector failures due to adverse localized equipment environments.

The applicant further states that as discussed in LRA Section 2.5-1 and Exhibit 2.5-1, Non-EQ cables in the steam tunnel were reviewed to identify if they supported any in-scope license renewal loads. None were identified. Non-EQ cables in the drywell were reviewed to identify if they support any in-scope license renewal loads. An adverse localized equipment environment was identified in the drywell for certain PVC cables. Through cable aging management review, the drywell was found to be the only adverse localized equipment environment at PBAPS for in-scope, Non-EQ cables. These cables in the drywell are PVC-insulated cables, and are used to provide safety relief valve discharge temperatures to control room temperature recorders in support of FSSD. The FSSD cables have their own aging management program, as described in LRA Section B.3.2.

Although the applicant believes a thorough review of cable insulation types was performed against the PBAPS design parameters for temperature and radiation in the presence of oxygen, and a plant walkdown did not identify any adverse localized equipment environments outside the drywell or steam tunnel, the applicant agrees to implement a Non-EQ accessible cable inspection program consistent with GALL Program XI.E1.

Table 3.6-1 of the LRA will be revised to reflect this new activity. Since all accessible cables installed in an adverse environment, including power, control, and instrumentation cables will be inspected, Table 3.6-1will not differentiate between insulation types as is shown in the original application.

Table 3.6-1 Aging Management Review Results for Cable

Component Group	Component Intended Function	Environment	Material of Construction	Aging Effect	Aging Management Activity
Electrical Cables	Electrical Continuity	Sheltered	Metallic conductor with various types of organic insulation (XLPE, EPR, EP, SR, etc.)	Loss of material properties	Non-EQ Accessible Cable Aging Management Activity (B.3.3)
Electrical Cables	Electrical Continuity	Sheltered	Metallic conductor with polyvinyl chloride (PVC) insulation	Loss of material properties	FSSD Cable Inspection Activity (B.3.2)

Appendix B.3, “New Aging Management Activities,” will be revised to reflect this new activity.

The staff finds the applicant's response acceptable because it will implement an aging management program for Non-EQ accessible cable to manage aging effects for cables in adverse localized environment caused by heat or radiation that has been reviewed by the NRC staff in GALL and found to be acceptable..

3.6.1.2.2 Aging Management Program

FSSD Cable Inspection Activities

The staff evaluated the information on aging effects caused by significant moisture and significant voltage, heat, and radiation, as presented in Section 2.5.1 of the LRA, to determine if there is a reasonable assurance that the applicant has demonstrated that the aging effects for accessible and inaccessible Non-EQ cables will be adequately managed, consistent with the applicant's CLB for the period of extended operation.

The staff asked the applicant (NRC question 22 of September 24-25, 2001 meeting) if the FSSD cable inspection activities are for instrumentation circuits. In response the applicant stated in a letter dated January 2, 2002, that the cable inspection activity for the FSSD cables do not apply to instrumentation circuits. The FSSD cables are connected to thermocouples on the discharge of the steam relief valves (SRVs) in the drywell, and provide temperature information to a recorder in the control room. The recorder provides both annunciation and input to the plant computer when an input signal is outside a preset allowable range. Although this arrangement may be considered a type of instrument circuit, it is not "loop checked" like a true instrument circuit, but provides direct readings to the recorder. The primary concern is with the PVC insulation surrounding the thermocouple metallic conductors, not with the metallic conductors themselves. With that in mind, it was considered that the most adequate inspection activity would be a visual inspection of PVC insulation consistent with GALL Report Program XI.E1, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements." Program XI.E2, "Electrical Cables Not Subject to 10 CFR 50.49 Environmental Requirements Used in Instrument Circuits," uses a combination of routine calibration and surveillance tests to identify the potential existence of aging degradation. This was considered to be an inadequate activity to identify the potential aging degradation of the PVC insulation of FSSD cables. The staff agrees with the applicant because FSSD cables are not for instrumentation circuits and visual inspection program is adequate for FSSD cable.

Staff Evaluation

The staff reviewed the FSSD cable inspection activity to determine whether it will ensure that all FSSD cables will continue to perform their intended function consistent with the CLB for the period of extended operation. The staff's evaluation of the FSSD cable inspection activity focused on how the program manages the aging effect through effective incorporation of the following 10 elements: program scope, preventive action, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience.

The application indicated that the corrective action elements, which includes the confirmation process to assure that the cause of the condition is determined and corrective action taken to preclude repetition, was credited for license renewal. Peach Bottom procedure AD-AA-101, "Processing of Procedures and T&RMs" governs creation and revision of site procedures and was the basis for the administrative control element in all PBAPS LRA Appendix B programs. The corrective action program and procedure AD-AA-101 are in accordance with the PBAPS Quality Assurance Program, which complies with 10 CFR Part 50, Appendix B. The staff's evaluation of the applicant's corrective action, confirmation process, and administrative controls is provided separately in Section 3.0.4 of safety evaluation report. The remaining seven elements are discussed below.

Program Scope: The scope of the activity includes evaluation of PV-insulated fire safe shutdown cables in the drywell that are within the scope of license renewal. The staff found the scope of the program acceptable because the program includes all insulated fire safe shutdown cables that are subject to potentially adverse localized environments.

Preventive Actions: FSSD cable inspection activities will be conducted for condition monitoring purposes. No preventive or mitigating attributes will be associated with FSSD cable inspection activities and the staff did not identify the need for such actions.

Parameter Monitored/Inspected: The PVC insulation will be visually inspected for surface anomalies such as embrittlement, discoloration, or cracking. The staff found this approach to be acceptable because it provides means for monitoring the applicable aging effects of FSSD cables.

Detection of Aging Effects: FSSD cable inspection activities will identify anomalies in the PVC insulation surface that are precursor indications of a loss of material properties for PVC-insulated cables. The staff found this activity to be acceptable on the basis that cable inspection activity is focused on detecting change in material properties of the conductor insulation, which is the applicable aging effect when cables are exposed to higher temperature.

Monitoring and Trending: Sample size of the inspection will be identified in the inspection activity. The PVC-insulated FSSD cables will be inspected once every 10 years. The applicant clarified that the first inspection will be performed before the end of the initial 40-year license term. Trending actions are not included as part of this program because the ability to trend inspection results is limited. The staff found that the 10-year inspection frequency will adequately preclude failures of the conductor insulation since aging degradation is a slow process. A 10-year inspection frequency will provide two data points during a 20-year period, which can be used to characterize the degradation rate. The visual technique is acceptable because it provides indication that can be visually monitored to preclude aging effects of FSSD cables. The staff also found that the absence of a trending acceptable.

Acceptance Criteria: Acceptance will require that no unacceptable visual indications of insulation surface anomalies exist that would suggest that the insulation has degraded, as determined by engineering evaluation. An unacceptable indication will be defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the intended function. The staff found this acceptance criterion to be acceptable because it should ensure that the intended function of the cables is maintained under all CLB design conditions during the period of extended operation.

Operating Experience: No age-related PVC-insulated FSSD cable failures have occurred at PBAPS. The staff found that the proposed inspection program will detect the adverse localized environment of FSSD cables.

UFSAR Supplement

The staff reviewed Section A.3.2 of the UFSAR Supplement (Appendix B of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

Conclusions

The staff concludes that the applicant has demonstrated that the aging effects associated with FSSD Cable Inspection activities will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.2(a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

Non-EQ Accessible Cable Aging Management Activity

Staff Evaluation

The staff evaluated the proposed Non-EQ Accessible Cable Aging Management Program. The evaluation of the applicant's proposed AMP focused on program elements rather than the details of specific plant procedures. To determine whether the applicant aging management programs are adequate to manage the effect of aging so that the intended function will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following seven elements: (1) scope of program, (2) preventive actions, (3) parameter monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, and (7) operating experience. The staff's evaluation of the applicant's corrective action, confirmation process, and administrative controls is provided separately in Section 3.0.4 of the staff's safety evaluation report.

Scope of Program: This inspection program applies to accessible electrical cables and connections (power, control, or instrumentation) within the scope of license renewal that are installed in adverse localized environments caused by heat or radiation in the presence of oxygen. Except for the low-level-signal instrumentation circuits discussed below (which are included in GALL program XI.E2), the staff concludes the scope of the program is acceptable because it includes all accessible Non-EQ cables and connections that are subject to potentially adverse localized environments of heat or radiation that could cause applicable aging effects in these cables and connections.

Preventive Action: This is an inspection program and no actions are taken as part of this program to prevent or mitigate degradation. This is acceptable because the staff did not identify the need for such actions.

Parameters Monitored or Inspected: A representative sample of accessible electrical cables and connections installed in adverse localized environments is visually inspected for cable and connection jacket surface anomalies, such as embrittlement, discoloration, cracking, or surface contamination. The staff found the inspection approach acceptable because it provides means for monitoring the applicable aging affects for accessible in-scope Non-EQ insulated cables and connections.

Detection of Aging Effects: Conductor insulation aging degradation from heat, radiation, or moisture in the presence of oxygen causes cable and connection jacket surface anomalies. Accessible electrical cables and connections installed in adverse localized environments are visually inspected at least once every 10 years. This is an adequate frequency to preclude failures of the conductor insulation since experience has shown that aging degradation is a slow process. A 10-year inspection frequency will provide two data points during a 20-year period, which can be used to characterize the degradation rate. The first inspection for license renewal is to be completed before the period of extended operation. The staff found that a 10-year inspection frequency is an adequate period to preclude failures of the conductor insulation since aging degradation is a slow process. The visual technique is acceptable because it provides indication that can be visually monitored to preclude aging effects of accessible cables and connections.

Monitored and Trending: Trending actions are not included as part of this program because the ability to trend inspection results is limited. The staff found the absence of trending acceptable because this inspection program is a new program.

Acceptance Criteria: The accessible cables and connections are to be free from unacceptable, visual indication of surface anomalies which suggest that conductor insulation or connection degradation exists. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the intended function. The staff found the acceptance criterion acceptable because it should ensure that the intended functions of the cables and connections are maintained under all CLB design conditions during the period of extended operation.

Operation Experience: Industry operating experience has shown that adverse localized environments caused by heat or radiation may exist for electrical cables and connections next to or above (within 3 feet of) steam generators, pressurizers, or hot process pipes such as feedwater lines. These adverse localized environments have been found to cause visually observable degradation (e.g. color changes or surface cracking) of the insulating materials on electrical cables and connections. These visual indications can be used as indicators of degradation. No age-related insulated Non-EQ cable failures due to adverse localized equipment environments have occurred at PBAPS. The staff found that the proposed inspection program will detect the adverse localized environments caused by heat or radiation of electrical cables and connections.

UFSAR Supplement

The staff reviewed the proposed Section A.3.3 of the UFSAR Supplement (Appendix B of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d). However, to be consistent with the commitment made in response to RAI

3.6-1, the applicant needs to provide a summary of description of the B.3.3, “Non-EQ accessible cable aging management activity” in the UFSAR Supplement. **This is Confirmatory Item 3.6.1.2.2-1.**

Conclusions

The staff concludes that the applicant has demonstrated that the aging effects associated with Non-EQ accessible cable aging management activity will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that, with the exception of Confirmatory Item 3.6.1.2.2-1, the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

In response to the staff’s request for an aging management program (RAI 3.6-1) for accessible and inaccessible electrical cables used in instrumentation circuits that are sensitive to reduction in conductor insulation resistance and exposed to an adverse localized environment caused by heat or radiation, the applicant states that it understands that the staff is requesting a program similar to GALL Report Program X1.E2, “Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits,” which uses routine calibration tests performed as part of the plant surveillance test program to identify the potential existence of aging degradation of cables and connections used in low-level-signal instrumentation that are sensitive to reduction in insulation resistance (IR) such as radiation monitoring and nuclear instrumentation.

The applicant stated that visual inspection can detect degradation early in the aging process whereas embrittlement and cracking must occur before significant electrical property changes, such as reduced resistance, would be detected through circuit calibration. Section 5.2.2, “Measurement of Component or Circuit Properties,” of SAND96-0344, “Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cable and Terminations,” dated September 1996, states,

> Significant changes in mechanical and physical properties (such as elongation-at-break and density) occur as a result of thermal-and radiation-induced aging. For low-voltage cables, these changes precede changes to the electrical performance of the dielectric. Essentially, the mechanical properties must change to the point of embrittlement and cracking before significant electrical changes are observed...

The industry understands that these two GALL programs (XI.E1 and XI.E2) manage the same aging effects for the same cables in different ways. This is seen as providing an applicant with the ability to pick the program that best fits the needs identified at the plant. Both programs are not be required to adequately manage aging of plant cables. Calvet Cliffs committed to the calibration program (XI.E2) but not to the inspection program, and Oconee committed to the inspection program (XI.E1) but not the calibration program. The industry saw this as a precedent and understood as being included in the GALL Report: the two programs cover the same cables using different methods to manage aging, and the applicant can choose a program that best fits the plant aging management requirements.

The staff notes that purpose of GALL Program XI.E1 is to provide reasonable assurance that the intended function of Non-EQ electrical cables and connections that are exposed to adverse localized environments caused by heat or radiation will be maintained consistent with the CLB through the period of extended operation. The cables included in this program do not include sensitive, low-signal-level instrumentation circuits or medium-voltage power cables. In Program XI.E1 a representative sample of accessible electrical cable and connection in adverse localized environments is visually inspected for cable and connection jacket surface anomalies. If an unacceptable condition or situation is identified for a cable or connection in the inspection sample, a determination is made as to whether the same condition is applicable to other accessible or inaccessible cables or connections. The purpose of GALL Program XI.E2 is to provide reasonable assurance that the intended functions of Non-EQ electrical cables that are used in sensitive low-level-signal circuits exposed to adverse localized environments caused by heat, radiation, or moisture will be maintained consistent with the CLB through the period of extended operation. In this program routine calibration tests performed as part of the plant surveillance test program are used to identify the potential existence of aging degradation. When an instrumentation loop is found to be out of calibration during routine surveillance testing, trouble shooting is performed on the loop, including the instrumentation cable. Thus, the two program cover different cables using different methods.

The aging management activity submitted by the applicant does not utilize the calibration approach for Non-EQ electrical cables used in circuits with low-level signals. Instead, these cables are simply combined with other Non-EQ cables under the visual inspection activity. The staff believes, however, that visual inspection alone may not necessarily detect reduced insulation resistance (IR) levels in cable insulation before the intended function is lost. Exposure of electrical cables to adverse localized environments caused by heat or radiation can result in reduced IR. A reduction in IR will cause an increase in leakage current between conductors and from individual conductors to ground, and is a concern for circuits with sensitive low-level signals such as in radiation and nuclear instrumentation since reduced IR may contribute to inaccuracies in instrument loop. Because low-level-signal instrumentation circuits may operate with signals that are normally in the picoamp range or less, they can affected by extremely low levels of leakage current. Routine calibration tests performed as part of the plant surveillance test program can be used to identify the potential existence of this aging degradation.

The staff was not convinced that aging of these cables will initially occur on the outer casing, resulting in sufficient damage that visual inspection will be effective in detecting the degradation before IR losses lead to a loss in intended function, particularly if the cables are also exposed to moisture. The staff undertook its own review of several aging management references. Page 3-52 of the SAND96-0344 report referenced by the applicant identifies polyethylene-insulated instrumentation cables located in close proximity to fluorescent lighting that had developed spontaneous circumferential cracks in exposed portions of the insulation. For some of the affected cables, the cracking was serve enough to expose the underlying conductor; however, no operational failures were documented as a result of this degradation.

Section 5.2.2 of SAND 96-0344 only assumes dry conditions where cable cracking occurs. “Aging and Life Extension of Major Light Water Reactor Components” edited by V.N Shaw and P.E. MacDonald on page 855 state that breaks in insulation systems that are dry and clean are normally not detectable with insulation resistance tests for 1000V or less. On the same page they also state that insulation resistance tests can detect some types of gross insulation damage, cracking of insulation, and the breach of connector seals, provided there is enough humidity or moisture to make the exposed leakage surfaces conductive.

Electric Power Research Institute (EPRI) report TR-103834-P1-2, “Effects of Moisture on the Life of Power Plant Cables” also supports the above view. It states on page 1.4-8 that normal or high insulation resistance may not indicate damaged insulation in that a throughwall cut or gouge filled with dry air may not significantly affect the insulation resistance. The SAND96-0344 report, on page 3-51, states that instances of low-voltage cable and wire shorting to ground induced by moisture may, in fact, be due to moisture intrusion through pre-existing cracking, an effect of thermal and/or radiation exposure.

The staff concludes from this literature that visual inspection of low-voltage, low-signal-level instrumentation circuits can be an effective means to detect age-related degradation due to adverse localized environments. The staff notes that the above finding on low-voltage instrumentation circuits is not necessarily true for neutron monitoring system cables. The SAND96-0344 report referenced by the applicant states on page 3.36 that neutron monitoring systems (including source, intermediate, and power range monitors) were evaluated as a separate category based on (1) their substantial difference from typical low- and medium-voltage power, control, and instrumentation circuits, and (2) the relatively large number of report related to these devices and identified in the database. The report states that neutron detectors are frequently energized at what is commonly referred to as “high” voltage, usually 1kV and 5kV. This is not high voltage compared to power transmission voltage, but rather elevated with respect to other portions of the detecting circuit. The report included the lower voltage non-detector portion of typical neutron monitoring equipment in the low-voltage equipment category, but put the 1kV to 5kV neutron detectors into a separate category that included neutron monitor cables and connectors.

The high-voltage portion of the neutron monitoring system would be a worst-case subset of the low-signal-level instrumentation circuit category. These circuits operate with low-level logarithmic signals so they are sensitive to relatively small changes in signal strength, and they operate at a high voltage, which could create larger leakage currents if that voltage is impressed across associated cables and connectors. Radiation monitoring cables have also been found to be particularly sensitive to thermal effects. NRC Information Notice 97-45, supplement 1, describes this phenomenon. The neutron monitoring and radiation monitors, therefore, might be candidates for the calibration approach but not necessarily the visual inspection approach.

The applicant should provide a technical justification for high range radiation monitor and neutron monitoring instrumentation cables to demonstrate that visual inspection will be effective in detecting damage before current leakage can affect instrument loop accuracy. **This is Open Item 3.6.1.2.2-1.**

3.6.1.3 Conclusions

The staff has reviewed the cable aging effects presented in Sections 2.5.1 and 3.6 of the LRA and the AMPs presented in Section B.3.2 and B.3.3 of Appendix B of the LRA. On the basis of the review, with the exception of **Open Items 3.6.1.2.1-1 and 3.6.1.2.2-1**, the staff concludes that the applicant has demonstrated that these AMPs adequately manage the effects of aging associated with the cables that are within the scope of license renewal so that the intended functions will be maintained consistent with the CLB for the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.6.2 Connectors, Splices, and Terminal Blocks

3.6.2.1 Technical Information in the Application

In Section 2.5.2 of the LRA, the applicant stated that the commodity group terminations includes electrical connectors, splices, and terminal blocks used for power, control, and instrumentation applications. PBAPS connectors, splices and terminal blocks that are part of the environmental qualification program were reviewed as time-limited aging analyses and the results are provided in Section 4.4.

The intended function of electrical connectors, splices, and terminal blocks is to provide electrical connections to specified sections of an electrical circuit to deliver voltage, current, or signals. The electrical connectors, splices, and terminal blocks are located in a sheltered environment.

The electrical connector materials subject to aging are metal and insulation. The metals used for electrical connectors are copper, tinned copper, and aluminum. The connector insulation materials used are various elastomers and thermoplastics.

The splice materials subject to aging is insulation. The insulation material used are various elastomers.

The electrical terminal block materials subject to aging are metal and insulation. The metals used for terminal blocks are copper, tinned copper, brass, bronze, and aluminum. The insulation materials used are phenolic compounds and nylon.

3.6.2.1.1 Aging Effects

The applicant does not identify any aging effects associated with connectors, splices, and terminal blocks, as indicated in Table 3.6-2 of the LRA.

3.6.2.1.2 Aging Management Program

The applicant provided the aging management review results for connectors, splices, and terminal blocks in Table 3.6-2 of the LRA. In this table, no aging management activity is required for the connectors, splices, and terminal blocks.

3.6.2.2 Staff Evaluation

The staff has evaluated the information on aging management presented in the Peach Bottom

LRA, Sections 2.5.2 and 3.6, and the applicant's response to the staff RAIs, dated January 2 and April 29, 2002. The staff evaluation was conducted to determine if there is a reasonable assurance that the applicant has demonstrated that the effects of aging will be adequately managed, consistent with its CLB throughout the period of extended operation, in accordance with 10 CFR 54.21(a)(3). This section of the SER provides the staff's evaluation of the applicant's aging management review for aging effects and the applicant's aging management program credited for the aging management of connectors, splices, and terminal blocks at Peach Bottom. The staff's evaluation includes a review of the aging effects considered. In addition, the staff has evaluated the applicability of the aging management program that is credited for managing the identified aging effects for the connectors, splices, and terminal blocks.

3.6.2.2.1 Aging Effects

The staff noted that low-voltage instrumentation circuits that are sensitive to small variations in impedance were determined to be potentially affected by oxidation of connectors and terminations that are used to terminate impedance-sensitive circuits (e.g., coaxial and triaxial connectors and terminations). Loss of materials caused by oxidation and corrosion of connector pins are aging concerns. The staff requested that the applicant provide an aging management program to manage these aging effects or provide technical justification for excluding it. In a response dated January 2, 2002, the applicant states that the connector materials subject to aging are metal and insulation. The metals used for low-voltage electrical connectors are copper, tinned copper, and aluminum. The connector insulation materials used are various elastomers and thermoplastics. Properly fitted and tight connections on uninsulated connectors protect the metallic contact surface area connection from environmental aging effects. Low-voltage (impedance-sensitive) instrumentation electrical connectors may experience failure when exposure to a wet environment induces corrosion or tarnishing of the metallic surface contact. The absence of a wet environment, with a properly fitted connection, precludes surface contact. A dry environment and a properly fitted connection preclude failure of an impedance-sensitive instrumentation connection through corrosion or tarnishing. Failures of electrical connectors that are not designed for wet environments are not age-related failures. Electrical connector failures resulting from water unexpectedly introduced into a normally dry area of the plant are event-driven or due to human error and are not age-related. This is confirmed in the NRC letter from Grimes to Walters, dated June 5, 1998, "License Renewal Issue No. 98-0013, 'Degradation Induced Human Activities'" which states that "the staff concludes that the issue of degradation induced by human activities need not be considered as a separate aging effect and should be excluded from aging management review." The applicant further stated in its response that a review of PBAPS operational history concluded that no age-related degradation due to oxidation of connectors has occurred at PBAPS . Therefore, the applicant concluded that no aging management activity is required. The staff finds the applicant's response acceptable because failures of electrical connectors resulting from connectors that are not designed for wet environments be installed in a wet environment, are not age-related failures. Electrical connector failures, resulting from water unexpectedly introduced into a normally dry area of the plant are event-driven or due to human error and are not age-related.

Peach Bottom LRA Section B.1.13, "Standby Liquid Control System Surveillance Activities," covers standby liquid control system (SBLC) components, including the solution tank, piping and valves on the suction side of the SBLC pump. The staff requested the applicant to explain why the electrical cables, connectors, and terminations were not included in this program in order to manage the aging effects of electrical components located in boric acid environments. In response to the staff's request, the applicant states that as a boiling water reactor (BWR), PBAPS has an SBLC system like that described in Section VII.E2 of NUREG-1801, "Generic Aging Lessons Learned (GALL) Report." The GALL report describes the components of the SBLC system are in contact with a sodium pentaborate solution. The sodium pentaborate solution provides a relatively mild environment with a slightly basic pH. Peach Bottom does not have a borated water environment; therefore, GALL Report Program XI.M10, "Boric Acid Corrosion," does not apply to PBAPS. There is no boric acid corrosion of any external surfaces, including the surfaces of cables, connections, and terminations. Additionally, the connectors and cables in the SBLC system are within protected enclosures so that sodium pentaborate leakage cannot degrade conductivity. The staff find the applicant's response acceptable because boric acid corrosion does not apply to PBAPS.

Section 3.6.2 of the LRA does not identify any applicable aging effects for Non-EQ connectors, splices, and terminal blocks. Industry experience indicates that change in material properties is an aging effect for connections (connectors, spices, and terminal blocks) that require aging management. In a letter dated January 23, 2002, the staff requested the applicant to provide an aging management program to manage the aging effects of accessible and inaccessible electrical connections exposed to an adverse localized environment caused by heat or radiation (RAI 3.6-1). The applicant responded with an proposed aging management activity to manage the aging effects for connections.

Table 3.6-2 of the LRA will be revised as shown below to reflect this new activity.

Table 3.6-2 Aging Management Review Results for Connectors, Splices, and Terminal Blocks

Component Group	Component Intended Function	Environment	Material of Construction	Aging Effect	Aging Management Activity
Electrical Connectors Insulation	Electrical Continuity	Sheltered	Various organic insulation types (discussed in Section 2.5.1)	Loss of Material Properties	Non-EQ Accessible Cable Aging Management Activity (B.3.3)
Electrical Connectors Metallic Connector	Electrical Continuity	Sheltered	Copper, tinned copper, and aluminum	None (2)	Not Applicable
Electric Splices Insulation	Electrical Continuity	Sheltered	Modified Polyolefin (XLPO, XLPE)	Loss of Material Properties	Non-EQ Accessible Cable Aging Management Activity (B.3.3)
Electrical Terminal Blocks Insulation	Electrical Continuity	Sheltered	Phenolic and nylon insulation	Loss of Material Properties	Non-EQ Accessible Cable Aging Management Activity (B.3.3)
Electrical Terminal Blocks Metallic	Electrical Continuity	Sheltered	Copper, tinned copper, brass, bronze & aluminum	None (2)	Not Applicable

(2) No aging effects for PBAPS

The revised Table 3.6-2 identifies loss of material properties as an aging effect of electrical connections. The staff finds with the applicant's response acceptable because loss of material properties is the aging effect of electrical connections.

3.6.2.2.2 Aging Management Programs

The applicant proposed an aging management program, “Non-EQ Accessible Cable Aging Management Activity,” for connectors, splices, and terminal blocks in a letter dated April 29, 2002. This program applies to electrical connectors, splices, and terminal blocks within the scope of license renewal that are installed in adverse localized environments caused by heat or radiation in the presence of oxygen. The staff found that the submitted aging management activity is essentially a visual inspection that addresses age-related degradation of connections that can result from exposure to high values of heat or radiation. In addition, fuse holders/blocks are classified as specialized type of terminal block because of the similarity in design and construction. Terminal blocks are passive components subject to an AMR for license renewal and so are fuse holders. During a conference call on September 5, 2002, the applicant stated that it will include fuse holders in the scope of the proposed AMP, Non-EQ accessible Cable Aging Management Activity (B.3.3), and this AMP will manage the aging effects for fuse connectors, splices, and terminal blocks as well as fuse holders. **This is Confirmatory Item 3.6.2.2.2-1.** The acceptability of this AMP has been evaluated in Section 3.6.1.2.2 of this SER. The staff therefore finds the aging management activity acceptable for providing reasonable assurance that the intended functions of Non-EQ connectors, splices, terminal blocks, and fuse holders that are exposed to adverse localized environments caused by heat or radiation will be maintained consistent with the CLB through the period of extended operation.

3.6.2.3 Conclusions

The staff concludes that, with the exception of Confirmatory Item 3.6.2.2.2-1, the applicant has demonstrated that the aging effects associated with connectors, splices, and terminal blocks will be adequately managed so there is reasonable assurance that the intended function of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21 (a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.6.3 Station Blackout System

3.6.3.1 Technical Information in the Application

In Section 2.5.3 of the LRA, the applicant states that the station blackout system comprises of the alternate AC (AAC) power source as required per NUMARC 87-00, “Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors.” The station blackout (SBO) system for PBAPS is in compliance with 10 CFR 50.63. The AAC power source consists of the following components:

- Conowingo Hydroelectric Plant (dam)
- Susquehanna substation
- wooden takeoff pole
- manholes at Conowingo and Peach Bottom
- Submarine cable (transmission line)

- station blackout substation at PBAPS

Conwingo Hydroelectric Plant (Dam)

The Conowingo Hydroelectric Plant (dam) is on the Susquehanna River approximately 10 miles north of the mouth of the river on the Chesapeak Bay, 5 miles south of the Pennsylvania border, and approximately 10 miles south of PBAPS. The Dam is the source of power to support the PBAPS SBO commitment. The Federal Energy Regulatory Commission (FERC) licenses the dam and associated power block. The dam is constructed primarily of concrete and steel. The associated power block consists of reinforce concrete and structural steel.

Susquehanna Substation

The Susquehanna substation is adjacent to and receives power from the Conowingo Hydroelectric Plant. The substation delivers 34.5kV power to PBAPS to support the SBO requirements. The substation has the standard industry power distribution design and consists of aluminum bus bars, insulators, circuit breakers, transformers, and associated foundations.

Wooden Pole

The takeoff tower for the transmission line from the Susquehanna substation is a wooden pole. The pole is constructed of yellow pine and chemically treated before installation. The installed pole has been analyzed to be able to withstand the severe weather conditions associated with the SBO event.

Manholes

Manholes exist at both the Conowingo Hydroelectric Plant and PBAPS locations to house the transition between the standard power cables from the substations at each location and the submarine cable. The manholes are constructed of reinforced concrete. AMRs of aging effects for concrete structures have concluded that no aging management activities are required, except for change in material properties due to leaching of calcium hydroxide

Submarine Cable (Transmission Line)

A 35kV submarine cable exits the manhole at Conowingo and runs under the bed of the Susquehanna River from just north of the dam to a manhole just south of the SBO substation. The submarine cable consists of copper phase conductors, ground conductors, EPR insulation, metallic shielding, and polyethylene (Okolene) jackets. The assembly of the submarine cable has three individually shielded and jacketed conductors cabled together with two ground conductors, and one fiber optic cable, with polypropylene fillers as necessary. A polypropylene bedding covers the entire cable and a layer of steel armor wires is applied over the bedding. Each wire is jacketed with black polyethylene. A nylon serving is then applied and an asphaltic solution is applied both under and over the armor and nylon serving.

PBAPS SBO Substation

PBAPS SBO substation consists of 34.5kV and 13.8kV metalclad outdoor walk-in switchgear, a 15/20 MVA oil-filled transformer, and associated breakers and controls. The SBO substation is designed as a stand-alone facility with control power coming from within the switchgear. The switchgear is contained within a standard prefabricated metal enclosure. The enclosure and switchgear foundation is discussed in LRA Section 2.4.6.

3.6.3.1.1 Aging Effects

Table 3.6-3, of the LRA identifies the following aging effects for the components of the wooden poles and Conowingo Hydroelectrical Plant:

- loss of material
- change in material properties

In Table 3.6-3, the applicant indicates that aging effects for concrete are evaluated in Section 3.5.6 of the LRA and that no aging effects are identified for aluminum, porcelain, and EPR insulation of the substation bus bas, substation insulators, and submarine cable, respectively.

3.6.3.1.2 Aging Management Program

Table 3.6-3 of the LRA credits the Wooden Pole Inspection and Conowingo Hydroelectric Plant Aging Management Program for managing the aging effects for the wooden pole and Conowingo Hydro Plant.

3.6.3.2 Staff Evaluation

The staff evaluated the information on aging management presented in the Peach Bottom LRA Sections 2.5.3 and 3.6.3 and the applicant's January 2, April 25, May 22, June 10, and July 29, 2002, responses to the staff RAIs. The staff evaluation was conducted to determine if there is a reasonable assurance that the applicant has demonstrated that the effects of aging will be adequately managed, consistent with its CLB throughout the period of extended operation, in accordance with 10 CFR 54.21(a)(3).

3.6.3.2.1 Aging Effects

Potential aging effects for insulators are surface contamination, cracking, and loss of material due to wear. Various airborne materials such as dust, salt, and industrial effluents can contaminate insulator surfaces. Porcelain is essentially a hardened, opaque glass. Like any glass, if subjected to enough force it will crack or break. The most common cause for cracking or breaking of an insulator is being struck by an object (e.g., a rock or bullet). Insulators also crack when the cement that binds the parts together expands enough to crack the porcelain. This phenomenon, known as cement growth, is caused by an improper manufacturing process which makes the cement more susceptible to moisture penetration. Mechanical wear is an aging effect for strain and suspension insulators because they move. An insulators can move when the wind blows the supported transmission conductor, swinging the conductor from side to side. If frequent enough, the swinging can cause wear in the metal contact points of the insulator string and between an insulator and the supporting hardware.

The staff requested the applicant to explain why no aging effects which require aging management was identified for bus bar insulators and the submarine cable. In response to the staff's concern regarding the aging management for bus bar insulators and submarine cables used in SBO, the applicant stated that porcelain insulators on the Susquahanna Substation bus bar and the insulator on the wooden pole were assessed for aging effects due to cracking, loss of material due to wear, and surface contamination. Cracking (known as cement growth) is caused by improper manufacturing and is not an applicable aging effect. Loss of material due to mechanical wear is an aging effect due to movement. Although this mechanism is possible, experience has shown that transmission conductors do not swing for very long once the wind has subsided. Therefore, this is not an applicable "significant and observable" aging effect. Surface contamination can be a problem in areas where there are great concentrations of airborne particles, such as near facilities that discharge soot or near the sea where salt spray is prevalent. Susquehanna substation and the wooden pole are in an area where airborne particle concentrations are comparatively low. Consequently, the contamination buildup on the insulators is insignificant, and surface contamination is not applicable aging effect. Therefore, no aging management activity is required for the bus bar and wooden pole insulators.

The submarine cable is designed for the environment it operates in (raw water). There are no aging effects from temperature and radiation. The cable is operated in an energized state with a load of approximately 1kVA. The cable is tested along with the other PBAPS SBO components every 2 years to assure it can support the required SBO loads. The PBAPS components of the SBO AAC source are maintained using procedures under the PBAPS QA program. In a letter to the applicant the manufacturer (Okonite) stated that it was "not aware of any age-related failures" of Okonite's Okoguard insulated submarine cables. Therefore, no aging management activity is required.

The staff found the applicant's response to the staff's RAI acceptable. As indicated above, the submarine cable is designed for the environment in which it operates and the contamination buildup on insulators is insignificant. The staff, therefore, concludes that the insulators and cables as defined above do not require an aging management activity at PBAPS.

In a May 22, 2002, response to the staff's request for additional information on the intended electrical function of the offsite power system within the scope of license renewal that provides recovery power after SBO event, the applicant states that it will include those applicable offsite power system structures and components required to support the description of recovery within the scope of license renewal and the aging management review process, as described in the NRC letter to Alan Nelson and David Lochbaum, "Staff Guidance on Scoping of Equipment Relied on To Meet the Requirement of the Station Blackout Rule (10CFR 50.63) for License Renewal (10CFR 54.4(a)(3)," dated April 1, 2002.

The offsite power system (the substation and the 13kV system) consists of three power sources and their associated structures and components and allows for power to be provided to the 4kV safeguard busses via the 13kV system. The substations have the standard industry power distribution design and consist of switchyard bus, insulators, circuit breakers, ground and disconnect switches, transformers, offsite power line poles, and associated switchgear and control buildings, foundation and supports. The offsite power system is discussed in UFSAR Section 8.1. The electrical components comprising the offsite power system were reviewed and the following passive, long-lived components were identified as subject to an AMR:

- switchyard bus
- high-voltage insulators
- insulated cables and connections (connectors, spices, terminal blocks)

- phase bus (non-segregated-phase bus)
- transmission conductors

The intended electrical function of the offsite power system within the scope of license renewal is to provide recovery after an SBO event. The AMR results for the electrical components are shown in Table 1 of the applicant's RAI response.

In Table 1 of the applicant's May 22, 2002, response to RAI 2.5-1 the applicant indicated that switchyard bus, outdoor/buried/sheltered insulated cables and connections, non-segregated phase bus, and transmission conductors have no aging effects and do not require aging management activity. In a telephone conference on June 18, 2002, the staff requested the applicant to explain why no aging effect was identified for these components. The staff also requested the applicant to identify any operating experience of the offsite power system components associated SBO. In response dated July 29, 2002, the applicant states that pure aluminum exposed to air may be susceptible to oxidation at connection points. However, no-oxide grease, a consumable which is replaced as required during routine maintenance, prohibits oxidation. Therefore, no aging effects are applicable.

A sheltered environment is defined on page 3-6 of the LRA. A sheltered environment consists of indoor ambient conditions where components are protected from outdoor moisture. No cables and connections associated with the SBO system and offsite power are in the drywell and steam tunnel. These cables experience temperatures of less than 105 °F and humidity between 10% and 90%. Radiation levels in this environment are less than 2.0E+06 inside the plant and normal background radiation levels outside the plant. No aging effects for cables and connections in this environment require management.

An outdoor environment is defined on page 3-7 of the LRA. An outdoor environment consists of air temperatures typically ranging from 0 °F to 100 °F, and an average annual precipitation of approximately 30 inches. Radiation levels are those of normal background levels. There are no aging effects for cables and connections in this environment.

A buried environment is defined on page 3-7 of the LRA. The buried environment consists of granular bedding material of sand or rock fines, backfill of dirt or rock, and filler material of gravel or crushed stone. A buried environment may include such items as ductbanks and conduits. The buried cables and connections associated with the offsite power sources, which may be susceptible to the phenomenon of water treeing, have been replaced. Direct buried cables exist in the substation. The cables are installed in a trench constructed of bar sand or stone screening both above and below the cables, with treated planking above the covered cables. As a result the cables in the trench experience normal "rain and drain" moisture and not standing water; therefore, they are not susceptible to water treeing.

With the exception of an oil fire several years ago in the substation, which was event driven, a review of PBAPS operating history indicates that PBAPS has not experienced any age-related degradation of the cables buried in the trench. The nonsegregated bus associated with the offsite power is in a sheltered environment and has no aging effects. The non-segregated bus duct that transitions from the #2SU startup and emergency auxiliary transformer to the #2 SU startup switchgear building is in an outdoor environment, discussed with structures, and is inspected by the Maintenance Rule Structural Monitoring Program. The overhead conductor is aluminum conductor steel reinforced (ACSR). Corrosion of ACSR is a very slow-acting aging effect and is even slower for rural areas such as PBAPS with generally fewer suspended particles and SO_2 concentrations in the air than urban areas. Therefore there are no applicable aging effects that require management.

The staff finds the applicant's response acceptable for switchyard bus, outdoor/sheltered insulated cables and connections, non-segregated-phase bus, and transmission conductors because it provides the rationale for why no aging effects are identified. The staff believes that water treeing can effect buried cables (other than 35kV submarine cables) associated with the offsite source and installed in ductbanks, conduits, and trenches. The staff acknowledges that the replacement cable is an improved formulation, which is more resistant to water-treeing. However, as discussed in Section 3.6.1.2.1, the staff does not accept the applicant's position that moisture is not an aging effect requiring an aging management for these cables. The staff is concerned that the applicant has not provided a sufficient technical justification for not requiring an aging management program for buried cables, not specifically designed for a wet environment. **This is the other part of Open Item 3.6.1.2.1-1.**

3.6.3.2.1 Aging Management Programs

The aging management review results for the station blackout system are provided in Table 3.6-3 of the LRA. The Conowingo Hydroelectric plant (Dam) Aging Management Program the will manage reinforced concrete and steel used in the Conowingo Hydroelectric Plant, and the Susquahanna Substation Wooden Pole Inspection Activity will manage the loss of material and change in material properties of wood used in wooden pole.

<u>Conowingo Hydroelectric Plant (Dam) Aging Management Program</u>

Section B.1.15 of the LRA describes the applicant's program for managing the potential aging of structures and components associated with the Conowingo Hydroelectric Plant dam. The staff reviewed Section B.1.15 of the LRA to determine whether the applicant has demonstrated that the inspection activities will adequately manage the applicable effects of aging during the period of extended operation as required by 10 CFR 54.21(a)(3).

The Conowingo Hydroelectric Plant is the source of power to support the PBAPS station blackout system, which was installed to meet the requirements of 10 CFR 50.63. The Conowingo dam is located on the Susquehanna River approximately 10 miles north of the mouth of the river on the Chesapeake Bay and approximately 10 miles south of PBAPS. The dam is constructed primarily of concrete and steel, and is exposed to raw water and an outside environment. The Federal Energy Regulatory Commission (FERC) licenses the dam and associated power block. The applicant credits the Conowingo Hydroelectric Plant (Dam) Aging Management Program with managing the potential loss of material of the dam.

Staff Evaluation

The applicant stated that the Conowingo Hydroelectric Plant dam is subject to the FERC 5-year inspection program. This program consists of a visual inspection by a qualified independent consultant approved by FERC, and is in compliance with Title 18 of the Code of Federal Regulations (Conservation of Power and Water Resources), Part 12 (Safety of Water Power Projects and Project Works), Subpart D (Inspection by Independent Consultant).

The applicant stated that the FERC licenses the dam and associated power block. By virtue of the FERC's authority and responsibility for ensuring that its regulated projects are constructed, operated, and maintained to protect life, health, and property, the staff finds that for earthen embankments, dams, appurtenances, and related structures subject to AMR, continued compliance with FERC requirements during the license renewal period will constitute an acceptable dam aging management program for the purposes of license renewal. Therefore, the staff finds the program acceptable.

UFSAR Supplement

The staff reviewed Section A.1.15 of the UFSAR Supplement (Appendix B of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides and adequate summary of program activities as required by 10 CFR 54.21(d).

Conclusions

The staff concludes that the applicant has demonstrated that the aging effects associated with Conowingo Hydroelectric Plant (dam) AMP will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

Susquehanna Substation Wooden Pole Inspection Activity

The applicant described the Susquehanna Substation Wooden Pole (SSWP) Inspection Activity AMP in Section B.2.11 of Appendix B of the LRA. The program is used to manage loss of material and change of material properties for the SSWP. The staff reviewed the applicant's description of the AMP in Section B.2.11 of Appendix B of the LRA to determine whether the applicant has demonstrated that the program will adequately manage the aging effects of the SSWP during the period of extended operation as required by 10 CFR 54.21(a)(3).

The SSWP inspection activity AMP is used to manage loss of material and change of material properties for the SSWP, a wooden pole at the Susquehanna substation. The pole provides structural support for the conductors connecting the substation to the cable that transmits the AC power to PBAPS from the Conowingo Hydraulic Plant for coping with station blackout. The wooden pole is subjected to outdoor and buried environments.

The AMP consists of inspection on a 10-year interval by a qualified inspector. The above-ground wooden pole exposed to the outdoor environment is inspected for loss of material due to ant, insect, and moisture damage and for change in material properties due to moisture damage. The applicant concluded that the SSWP inspection activity AMP manage the aging effects of loss of material and change in material properties so that the component intended functions will be maintained consistent with the CLB during the period of extended operation.

In accordance to 10 CFR 54.21(a)(3), the staff reviewed the information included in Appendix B of the LRA regarding the applicant's SSWP inspection activity AMP. Specifically, the LRA should demonstrate that the effects of aging due to the exposure of the wooden pole to outdoor and buried conditions will be adequately managed, allowing the intended functions to be maintained consistent with the CLB for the period of extended operation.

Staff Evaluation

The staff's evaluation of the Susquehanna substation wooden pole inspection activity focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

Program Scope: The applicant stated that the program only applies to the SSWP. The staff finds the scope of the program acceptable.

Preventive Actions: The applicant described the AMP as a condition monitoring AMP. No preventive or mitigation actions are provided. The staff considers inspection activities a means of detecting, not preventing, aging and, therefore, agrees that no preventive actions are associated with the wooden pole inspection activity and none are required.

Parameters Monitored or Inspected: The applicant stated that the wooden pole is inspected for loss of material due to ant, insect, and moisture damage and for change in material properties due to moisture damage. In RAI B2.11-1, the staff requested information on what parameters and material properties are monitored/inspected and how the buried part of the wooden pole is monitored/inspected. In a letter dated June 10, 2002, the applicant responded that aging management activities for wooden poles consist of visual inspections, sounding, and, if required, boring and excavation activities. Each inspection consists of a visual inspection of the entire pole from the ground up. Parameters inspected include shell rot, decay pockets, heart rot, rotten butt, cracked or broken arms or braces, mechanical damage, ground line decay, split tops, etc. Each pole is sounded by striking each quadrant of the pole surface several times with a sounding hammer around the circumference from the ground line to as high as the inspector can reach. If poles are found to have ground line decay they are excavated and inspected 18 inches below the ground line. If internal decay is suspected, the pole is bored to allow for further analysis. The staff finds the parameters monitored or inspected acceptable because they are capable of detecting the aging effects.

Detection of Aging Effects: The applicant stated that inspection of the wooden pole every 10 years by a qualified inspector will assure that aging effects are detected prior to loss of intended function. In the RAI B2.11-2, the staff requested justification for the 10-year inspection interval of the wooden pole. In a letter dated June 10, 2002, the applicant explained that the typical life for a wooden pole, based on industry experience, is 30-40 years. If the pole is inspected and treated with a pesticide, fumigant, or preservative solution every 10 years, as required, it should last 10 to 15 years longer. Plant experience over several decades has indicated that a 10-year inspection interval is adequate. The Susquehanna wooden pole was installed in 1994. The first inspection is scheduled for 2003. The pole will be inspected every 10 years thereafter. The staff finds the 10-year inspection interval acceptable because it is based plant and industry experience.

Monitoring and Trending: The applicant stated that condition monitoring for loss of material and change in material properties is provided in the station specification for inspection of wooden poles. The wooden pole is inspected at 10-year intervals. The monitoring under this AMP involves a combination of visual, sounding, boring, and excavation activities to determine the condition of the pole. Any shell rot, decay pockets, heart rot, rotten butt, cracked or broken arms or braces, mechanical damage, ground line decay, split tops, etc., which may limit the life of the pole or which require immediate attention in the interest of safety are recorded, and reported. Therefore, the staff finds the applicant's approach to monitoring activities to be acceptable because it is based on methods that are sufficient to predict the extent of degradation so that timely corrective or mitigative actions are possible.

Acceptance Criteria: The applicant stated that the acceptance criteria for the inspection are provided in the station specification for inspection of wooden poles. In RAI B.2.11-3, the staff requested a description of the acceptance criteria in terms of (1) assessing the severity of the observed degradations and (2) determining whether corrective action is necessary. In a letter dated June 10, 2002, the applicant explained that an approved wooden pole maintenance contractor experienced in the inspection, treatment, and reinforcement of wooden poles performs the pole inspection. Personnel handling treatment material are licensed pesticide applicators. The inspector, through a combination of visual, sounding, boring, and excavation activities, determines the condition of the pole. If sounding indicates internal decay, or a hollow pole, boring will determine the extent of the decayed area. Pesticide treatment will occur as required. If any poles (except poles requiring replacement) found to contain ants or termites, the cavities where the ants or termites are found are flooded with an effective preservative solution. Any pole determined to have internal decay will receive fumigant treatment. Each wooden pole that is inspected receives a condition tag describes the pole condition as found by the inspector and whether the pole has received treatment. Based on the remaining shell thickness (circumference) and pole loading, poles can be tagged as requiring either reinforcement or replacement. The staff finds the acceptance criteria acceptable.

Operating Experience: The first inspection of the pole is scheduled for 2003, so there is no experience with this specific pole; however, the applicant stated that corporate experience shows that inspection of wooden poles once every 10 years is adequate to detect aging degradation prior to loss of intended function, based on industry experience. The staff finds this reasonable and acceptable.

UFSAR Supplement

The staff reviewed Section A.2.11 of the UFSAR Supplement (Appendix B of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides and adequate summary of program activities as required by 10 CFR 54.21(d).

Conclusions

The staff concludes that the applicant has demonstrated that the aging effects associated with Susquehanna Substation Wooden Pole Inspection Activity will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.6.3.3 Conclusions

The staff has reviewed the Station Blackout system aging effects presented in Section 3.6.3 of the LRA and the AMPs presented in Sections B.1.15 and B.2.11 of Appendix B of the LRA. On the basis of the review, with the exception of Open Item 3.6.1.2.1-1, the staff concludes that the applicant has demonstrated that these AMPs adequately manage the effects of aging associated with Station Blackout systems components that are within the scope of license renewal so that the intended functions will be maintained consistent with the CLB for the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).