NUREG-1769

Safety Evaluation Report
Related to the License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3

Docket Nos. 50-277 and 50-278

Exelon Generation Company, LLC (Exelon)

U.S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation
Washington, DC 20555-0001

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Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

ABSTRACT

This document is a safety evaluation report regarding the application to renew the operating licenses for Peach Bottom Atomic Power Station, Units 2 and 3. The application was filed by the Exelon Generation Company LLC, (Exelon) by letter dated July 2, 2001. The Office of Nuclear Reactor Regulation has reviewed the Peach Bottom Atomic Power Station, Units 2 and 3, license renewal application for compliance with the requirements of Title 10 of the Code of Federal Regulations, Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," and prepared this report to document its findings.

In its submittal of July 2, 2001, Exelon requested renewal of the Peach Bottom, Units 2 and 3, operating licenses (License Nos. DPR-44 and DPR-56, respectively), which were issued under Section 104b of the Atomic Energy Act of 1954, as amended, for a period of 20 years beyond the current license expiration dates of August 8, 2013, and July 2, 2014, respectively. The Peach Bottom Atomic Power Station is a two-unit nuclear power plant located in York County and Lancaster County in southeastern Pennsylvania. Each unit consists of a General Electric boiling-water reactor nuclear steam supply system designed to generate 3514 megawatts thermal or approximately 1116 megawatts electric.

The NRC license renewal project manager for Peach Bottom, Units 2 and 3, is David Solorio. Mr. Solorio may be contacted by calling 301-415-1973 or by writing to the License Renewal and Environmental Impacts Program, U.S. Nuclear Regulatory Commission, Washington, DC 20555-001.

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ACRONYMS

AAC	alternate ac
AASHTO	American Association of State Highway and Transportation Official
ACI	American Concrete Institute
ACSR	aluminum conductor steel reinforced
ADS	automatic depressurization system
AMP	aging management program
AMR	aging management review
ANL	Argonne National Laboratory
AO	abnormal occurrence
APCSB	Auxiliary and Power Conversion Systems Branch
ARI	alternate rod insertion
ART	anticipatory reactor trip
ASCO	American Switch Company
ASME	American Society of Mechanical Engineers
ATWS	anticipated transient without scram
BESVS	Battery and Emergency Switchgear Ventilation Systems
BPT	Branch Technical Position
BWR	boiling water reactor
BWROG	boiling water reactor owners group
BWRVIP	Boiling Water Reactor Vessel and Internals Project
CAC	containment atmosphere control (system)
CAD	containment atmospheric dilution (system)
CASS	cast austenitic stainless steel
CCW	closed cooling water
CDF	core damage frequency
CFR	Code of Federal Regulations
CLB	current licensing basis
CRD	control rod drive
CRDHS	control rod drive housing supports
CRL	component record list
CRVS	control room ventilation system
CST	condensate storage tank
CUF	cumulative usage factor
DBA	design-basis accidents
DBD	design baseline document
DBE	design basis event
DGBVS	diesel generator building ventilation system
DRF	dose reduction factor
ECCS	emergency core cooling system
ECP	electrochemical potential
ECT	emergency cooling tower
ECW	emergency cooling water (system)
EDG	emergency diesel generator
EFPY	effective full-power years
EPDM	ethylene propylene dienyl monomer
EPRI	Electric Power Research Institute

EQ	environmental qualification
ESF	engineered safety feature
ESW	emergency service water (system)
FAC	flow-accelerated corrosion
FERC	Federal Energy Regulatory Commission
FMP	fatigue monitoring program
FPP	fire protection program
FSAR	final safety analysis report
FSSD	fire safe shutdown
GDC	general design criteria
GL	generic letter
GSI	Generic Safety Issues
HEDL	Hanford Engineering and Development Laboratory
HELB	high-energy line break
HEPA	high-efficiency particulate air
HPCI	high-pressure coolant injection (system)
HPSW	high-pressure service water (system)
HVAC	heating, ventilation, and air conditioning
HWC	hydrogen water chemistry
HX	heat exchanges
I & C	instrumentation and controls
IASCC	irradiation assisted stress corrosion cracking
ICEA	Insulated Cable Engineers Association
ICM	Instrument Control Monitor
IGSCC	intergranular stress corrosion cracking
ILRT	integrated leak rate test
IN	information notice
INPO	Institute of Nuclear Power Operations
IPA	integrated plant assessment
IPE	individual plant evaluation
IPEEE	individual plant examination of external events
ISI	inservice inspection
IST	inservice testing
LEFM	linear elastic fracture mechanics
LER	licensee event report
LLRT	local leak rate tests
LMFBR	Liquid Metal Fast Breeder Reactor
LOCA	loss of coolant accident
LPCI	low-pressure coolant injection (system)
LPRM	local power range monitor
LRA	license renewal application
LRC	level recorder controller
LWR	light-water reactor
MCC	motor control center
MCRE	main control room envelope
MCRE	main control room envelope
MIC	microbiologically influenced corrosion
MOV	motor-operated valve

MR	maintenance rule
MSIV	main steam isolation valve
MSRV	main steam relief valve
NCR	nonconformance report
NDE	nondestructive examination
NEI	Nuclear Energy Institute
NEMA	National Electrical Manufactures Associates
NFPA	National Fire Protection Association
NMCA	noble metals chemical addition
NPAR	nuclear plant aging research
NRC	Nuclear Regulatory Commission
NSAC	Nuclear Safety Analysis Center
NSR	non-safety related
NSSS	nuclear steam supply systems
NSW	normal service water
NUMARC	Nuclear Management and Resources Council
OE	operating experience
OFS	orificed fuel support
ORNL	Oak Ridge National Laboratory
P&ID	piping and instrumentation diagram
PBAPS	Peach Bottom Atomic Power Station
PCIS	primary containment isolation system
PECO	Philadelphia Electric Company
PLI	project level instruction
PM	preventive maintenance
P-T	pressure-temperature
PSVS	pump structure ventilation system
PUA	plant-unique analysis
PWR	pipe whip restraint
QAP	quality assurance procedure
RAI	request for additional information
RBM	rod block monitor
RCIC	reactor core isolation cooling (system)
RCS	reactor coolant system
RG	Regulatory Guide
RHR	residual heat removal (system)
RMS	radiation monitoring system
RPS	reactor protection system
RPV	reactor pressure vessel
RRS	reactor recirculation system
RTNDT	nil-ductility transition reference temperature
RVID	reactor vessel integrity database
RWM	rod worth minimizer
RWCU	reactor water cleanup
RWST	refueling water storage tank
SBLC	standby liquid control (system)
SBO	station blackout
SCC	stress corrosion cracking

SE	safety evaluation
SECY	Secretary of the Commission Office of the (NRC)
SER	safety evaluation report
SGIG	safety grade instrument gas (system)
SGTS	standby gas treatment system
SIL	Service Information Letter
SLC	standby liquid control
SOER	significant operating experience reports
SPOTMOS	suppression pool temperature monitoring system
SRM	source range monitor
SRP-LR	Standard Review Plan - license renewal
SRV	safety relief valve
SCs	structures and components
SSCs	systems, structures, and components
SV	safety valve
SSWP	Susquehanna Substation Wooden Pole
TID	total integrated dose
TLAAs	time-limited aging analyses
TTA	thenyltrifluoroacetone
UFSAR	updated final safety analysis report
UL	Underwriters Laboratories, Inc.
USAS	United States of America Standards
USE	upper-shelf energy
USI	unresolved safety issue
WRNM	wide range neutron monitor
XLPE	cross-linked polyethylene
XLPO	cross-linked polyolefin

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1 INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

This document is a safety evaluation report (SER) on the application to renew the operating licenses for Peach Bottom Atomic Power Station, Units 2 and 3, filed by Exelon Generation Company, LLC, (Exelon) (hereafter referred to as Exelon or the applicant).

By letter dated July 2, 2001, Exelon submitted its application to the U.S. Nuclear Regulatory Commission (NRC) for renewal of the operating licenses for Peach Bottom Atomic Power Station, Units 2 and 3, for an additional 20 years. The NRC staff reviewed the Peach Bottom license renewal application (LRA) for compliance with the requirements of Title 10 of the Code of Federal Regulations, Part 54 (10 CFR Part 54), "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," and prepared this report to document its findings. The NRC's license renewal project manager for Peach Bottom Atomic Power Station, Units 2 and 3, is David Solorio. Mr. Solorio may be contacted by calling 301-415-1973 or by writing to the License Renewal and Environmental Impacts Program, U.S. Nuclear Regulatory Commission, Washington, DC 20555-001.

In its application, Exelon requested renewal of the operating licenses issued under Section 104b of the Atomic Energy Act of 1954, as amended, for Peach Bottom Atomic Power Station, Units 2 and 3 (License Nos. DPR-44 and DPR-56, respectively) for a period of 20 years beyond the current license expiration dates of August 8, 2013 and July 2, 2014, respectively. The Peach Bottom Atomic Power Station is a two-unit boiling water reactor located in York County and Lancaster County in southeastern Pennsylvania. Each unit consists of a General Electric boiling-water reactor nuclear steam supply system designed to generate 3458 megawatts thermal or 1093 megawatts electric. Details concerning the plant and the site are found in the updated final safety analysis report (UFSAR) for each unit.

The license renewal process proceeds along two tracks: a technical review of safety issues and an environmental review. The requirements for these two reviews are stated in NRC regulations 10 CFR Parts 54 and 51, respectively. The safety review is based on Exelon's application for license renewal and on the applicant's answers to requests for additional information (RAIs) from the NRC staff. Exelon has also supplemented its answers to the RAIs in meetings and docketed correspondence. The public can review the LRA and all pertinent information and material, including the UFSARs, at the NRC Public Document Room, 11555 Rockville Pike, Rockville, MD 20852-2738. In addition, the Peach Bottom Atomic Power Station, Units 2 and 3, LRA and significant information and material related to the license renewal review are available on the NRC's Website at www.nrc.gov through the NRC's electronic reading room.

This SER summarizes the findings of the staff's safety review of the Peach Bottom Atomic Power Station, Units 2 and 3, and describes the technical details considered in evaluating the safety aspects of its proposed operation for an additional 20 years beyond the term of the current operating licenses. The staff reviewed the LRA in accordance with the NRC regulations and the guidance presented in the NRC "Standard Review Plan (SRP) for the Review of License Renewal Applications for Nuclear Power Plants," dated July 2001.

1.2 License Renewal Background

Pursuant to the Atomic Energy Act of 1954, as amended, and NRC regulations, operating licenses for commercial power reactors are issued for 40 years. These licenses can be renewed for up to 20 additional years. The original 40-year license term was selected on the basis of economic and antitrust considerations, not technical limitations. However, some individual plant and equipment designs may have been engineered on the basis of an expected 40-year service life.

In 1982, the NRC anticipated interest in license renewal and held a workshop on nuclear power plant aging. That led the NRC to establish a comprehensive program plan for nuclear plant aging research (NPAR). On the basis of the results of that research, a technical review group concluded that many aging phenomena are readily manageable and do not involve technical issues that would preclude extending the life of nuclear power plants.

In 1986, the NRC published a request for comment on a policy statement that would address major policy, technical, and procedural issues related to life extension for nuclear power plants.

In 1991, the NRC published the license renewal rule in 10 CFR Part 54. The NRC participated in an industry-sponsored demonstration program to apply the rule to pilot plants and develop experience to establish implementation guidance. To establish a scope of review for license renewal, the rule defined age-related degradation unique to license renewal. However, during the demonstration program, the NRC found that many aging mechanisms occur and are managed during the period of the initial license. In addition, the NRC found that the scope of the review did not allow sufficient credit for existing programs, particularly for the implementation of the Maintenance Rule, which also manages plant aging phenomena.

As a result, in 1995 the NRC amended the license renewal rule in 10 CFR Part 54. The amended rule established a regulatory process that is simpler, more stable, and more predictable than the previous license renewal rule. In particular, 10 CFR Part 54 was clarified to focus on managing the adverse effects of aging rather than on identifying all aging mechanisms. The rule changes were intended to ensure that important systems, structures, and components (SSCs) will continue to perform their intended function in the period of extended operation. In addition, the integrated plant assessment (IPA) process was clarified and simplified to be consistent with the revised focus on passive, long-lived structures and components (SCs).

In parallel with these efforts, the NRC pursued a separate rulemaking effort to amend 10 CFR Part 51 to focus the scope of the review of environmental impacts of license renewal, and fulfill, in part, the NRC's responsibilities under the National Environmental Policy Act of 1969 (NEPA).

1.2.1 Safety Review

License renewal requirements for power reactors are based on two key principles:

(1) The regulatory process is adequate to ensure that the licensing basis of all currently operating plants maintains an acceptable level of safety, with the possible exception is the detrimental effects of aging on the functionality of certain SSCs during the period of

extended operation, and a few other safety issues may arise only during the period of extended operation

(1) The plant-specific licensing basis must be maintained during the renewal term in the same manner and to the same extent as during the original licensing term.

In implementing these two principles 10 CFR 54.4 defines the scope of license renewal as including those plant SSCs (a) that are safety-related, (b) whose failure could affect safety-related functions, (c) that are relied on to demonstrate compliance with the Commission's regulations for fire protection, environmental qualification, pressurized thermal shock, anticipated transients without scram, and station blackout.

Pursuant to 10 CFR 54.21(a)(1), the applicant must review all SSCs that are within the scope of the rule to identify SCs that are subject to an aging management review (AMR). SCs that are subject to an AMR are those that perform an intended function without moving parts or without a change in configuration or properties and that are not subject to replacement based on a qualified life or specified time period. As required by 10 CFR 54.21(a), the applicant must demonstrate that the effects of aging will be managed in such a way that the intended function or functions of the SCs that are within the scope of license renewal will be maintained, consistent with the current licensing basis, for the period of extended operation.

Active equipment, however, is considered to be adequately monitored and maintained by existing programs. The detrimental effects of aging on active equipment are more readily detectable and will be identified and corrected through routine surveillance, performance indicators, and maintenance. The surveillance and maintenance programs and activities for active equipment, as well as other aspects of maintaining the plant design and licensing basis, are required to continue throughout the period of extended operation.

Pursuant to 10 CFR 54.21(b), each year following submittal the LRA and at least 3 months before the scheduled completion of the NRC review, an amendment to the renewal application must be submitted that identifies any change to the CLB of the facility that materially affects the contents of the LRA, including the FSAR supplement.

Another requirement for license renewal is the identification and updating of time-limited aging analyses. During the design phase for a plant, certain assumptions are made about the initial operating term of the plant, and these assumptions are incorporated into design calculations for several of the plants SSCs. In accordance with 10 CFR 54.21(c)(1), these calculations must be shown to be valid for the period of extended operation or must be projected to the end of the period of extended operation, or the applicant must demonstrate that the effects of aging on these SSCs will be adequately managed for the period of extended operation. Pursuant to 10 CFR 54.21(c)(2), each applicant must provide a list of the exemptions granted pursuant to 10 CFR 50.12 and still in effect that are based on the TLAAs as defined in 10 CFR 54.3. Pursuant to CFR 54.21(c)(2), each applicant must also provide an evaluation that justifies the continuation of these exemptions for the period of extended operation.

Pursuant to 10 CFR 54.21(d), each application is required to include a supplement to the FSAR. This supplement must contain a summary description of the programs and activities for managing the effects of aging, and the evaluation of TLAAs for the period of extended operation.

In July 2001, the NRC issued Regulatory Guide 1.188, “Standard Format and Content for Applications to Renew Nuclear Power Plant Operating License”; NUREG-1800, “Standard Review Plan for the Review of License Renewal Application for Nuclear Power Plants” (SRP-LR); and NUREG-1801, “Generic Aging Lessons Learned (GALL) Report.” These documents describe methods acceptable to the NRC staff for implementing the license renewal rule, as well as techniques used by the NRC staff in evaluating applications for license renewals. The draft versions of these documents were issued for public comment on August 31, 2000 (64 FR 53047). The staff assessment of public comments was issued as NUREG-1739, “Analysis of Public Comments on the improved License Renewal Guidance Documents.” The regulatory guide endorsed an implementation guideline prepared by the Nuclear Energy Institute (NEI) as an acceptable method of implementing the license renewal rule. The NEI guideline is NEI 95-10, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54–The License Renewal Rule," Revision 3 issued in April 2001. The staff used the RG1.188, along with the SRP, to review this application and to assess topical reports on license renewal issues as submitted by industry groups.

1.2.2 Environmental Review

In December 1996, the staff revised the environmental protection regulations in 10 CFR Part 51 to facilitate environmental reviews for license renewal. The staff prepared a “Generic Environmental Impact Statement (GEIS) for License Renewal of Nuclear Plants” (NUREG-1437) to document its evaluation of the possible environmental impacts associated with renewing licenses of nuclear power plants. For certain types of environmental impacts, the GEIS establishes generic findings that are applicable to all nuclear power plants. These generic findings are identified as Category 1 issues in 10 CFR Part 51, Subpart A, Appendix B. Pursuant to 10 CFR 51.53(c)(3)(i), an applicant for license renewal may incorporate these generic findings in its environmental report. Analyses of environmental impacts of license renewal that must be evaluated on a plant-specific basis are identified as Category 2 issues in 10 CFR Part 51, Subpart A, Appendix B. Such analyses must be included in an environmental report in accordance with 10 CFR 51.53(c)(3)(ii).

In accordance with NEPA and the requirements of 10 CFR Part 51, the NRC performs a plant-specific review of the environmental impacts of license renewal, including whether there is new and significant information not considered in the GEIS. Two public meetings were held near the Peach Bottom site on November 7, 2001, as part of the NRC's scoping process to identify environmental issues specific to the plant. The results of the environmental review and a preliminary recommendation on the license renewal action were documented in NRC draft plant-specific Supplement 10 to the GEIS, dated June 2002. Two additional public meetings were conducted near the site on July 31, 2002 (during the 75-day comment period for draft plant-specific Supplement 10 to the GEIS). At the meetings, the staff described the environmental review, accepted comments, and answered questions from members of the public. The Final Supplement 10 to the GEIS was issued on January 22, 2003.

The Final Supplement 10 to the GEIS presents the NRC’s environmental analysis of the effects of renewing the Peach Bottom Units 2 and 3 operating licenses for up to an additional 20 years. The analyses considered and weighed the environmental effects and alternatives that are available to avoid adverse environmental effects. On the basis of the analyses and findings in the GEIS, the environmental report submitted by the applicant, consultation with other Federal, State, and local agencies, its own independent review, and its consideration of public comments, the staff recommended in Supplement 10 that the Commission determine that the adverse environmental impacts of license renewal for Peach Bottom Units 2 and 3 are not so great that preserving the option of license renewal for energy planning decision-making would be unreasonable.

1.3 Summary of the Principal Review Matters

The requirements for renewing operating licenses for nuclear power plants are described in 10 CFR Part 54. The staff performed its technical review of the Peach Bottom Atomic Power Station, Units 2 and 3, license renewal application in accordance with Commission guidance and the requirements of 10 CFR Part 54. The standards for renewing a license are contained in 10 CFR 54.29.

In 10 CFR 54.19(a), the Commission requires a license renewal applicant to submit general information. Exelon submitted this general information in an enclosure to its July 2, 2001, application for renewed operating licenses for Peach Bottom Atomic Power Station, Units 2 and 3. The applicant supplemented this information in a letter dated August 23, 2001. The staff reviewed the enclosure and the supplemental information.

In 10 CFR 54.19(b), the Commission requires that LRAs include “conforming changes to the standard indemnity agreement, 10 CFR 140.92, Appendix B, to account for the expiration term of the proposed renewed license.” The applicant stated the following in its renewal application regarding this issue:

> The current indemnity agreement for Peach Bottom Atomic Power Station, Units 2 and 3 states in Article VII that the agreement shall terminate at the time of expiration of the license specified in Item 3 of the Attachment to the agreement. Item 3 of the Attachment to the indemnity agreement, lists two license numbers, DRP-44 and DRP-56. Should the license numbers be changed upon issuance of the renewed licenses, Exelon requests that the conforming changes be made to Article VII and Item 3 of the Attachment, and to any other sections of the indemnity agreement as appropriate.

The staff will use the original license number for the renewed license. Therefore, there is no need to make conforming changes to the indemnity agreement, and the requirements of 10 CFR 54.19(b) have been met.

In 10 CFR 54.21, the Commission requires that each application for a renewed license for a nuclear facility must contain (a) an integrated plant assessment (IPA), (b) description of current licensing basis changes made during the NRC review of the application, (c) an evaluation of time-limited aging analyses (TLAAs), and (d) a final safety analysis report (FSAR) supplement. On July 2, 2001, the applicant submitted the information required by 10 CFR 54.21(a) and (c) in the Enclosure of its LRA.

In 10 CFR 54.22, the Commission states requirements regarding technical specifications. The applicant did not request any changes to the plant technical specification in its LRA.

The staff evaluated the technical information required by 10 CFR 54.21 and 54.22 in accordance with the NRC's regulations and the guidance provided in the SRP. The staff's evaluation of this information is documented in Chapters 2, 3, and 4 of this SER.

The staff's evaluation of the environmental information required by 10 CFR 54.23 is documented in the plant-specific supplement to the GEIS (NUREG-1437, Supplement 10), which states the considerations related to renewing the licenses for Peach Bottom Atomic Power Station, Units 2 and 3.

1.3.1 Boiling Water Reactor Vessel Internals Project (BWRVIP) Topical Reports

In accordance with 10 CFR 54.17(e), Exelon also incorporated by reference several BWRVIP topical reports into the Peach Bottom LRA. The purpose of the topical reports is to generically demonstrate that the aging effects for reactor coolant system components are adequately managed for the period of extended operation under a renewed license. Exelon incorporated the following BWRVIP topical reports into its application:

- BWRVIP-05, "BWR RPV Shell Weld Inspection Recommendations," September 1995
- BWRVIP-18, "Core Spray Internals Inspection and Flaw Evaluation Guidelines," July 1996
- BWRVIP-25, "BWR Core Plate Inspection and Flaw Evaluation Guidelines," October 1999
- BWRVIP-26, "Top Guide Inspection and Flaw Evaluation Guidelines," December 1996
- BWRVIP-27, "Standby Liquid Control System/Core Plate ΔP Inspection and Flaw Evaluation Guidelines," April 1997
- BWRVIP-38, "Shroud Support Inspection and Flaw Evaluation Guidelines," September 1997
- BWRVIP-41, "BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines," October 1997
- BWRVIP-47, "BWR Lower Plenum Inspection and Flaw Evaluation Guidelines," December 1997
- BWRVIP-48, "Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines," March 1998
- BWRVIP-49, "Instrument Penetration Inspection and Flaw Evaluation Guidelines," March 1998
- BWRVIP-74, "BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines," September 1999

- BWRVIP-75, “Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules (NUREG-0313),” October 1999

- BWRVIP-76, “BWR Core Shroud Inspection and Flaw Evaluation Guidelines,” December 1999

All the BWRVIP reports listed above have been approved by the staff with the exception of BWRVIP-76. The staff is presently reviewing the responses from the Owners Group, and is expected to issue a safety evaluation report by the end of 2003. Because the staff’s review is not complete the license will be conditioned as discussed below in Section 1.6.

The applicant committed to follow the BWRVIP reports as approved by the staff. The staff finds this commitment to be acceptable for aging management of the systems and components addressed in the subject BWRVIP reports.

1.4 Summary of Open Items

As a result of its review of the license renewal application for the Peach Bottom Atomic Power Station Units 2 & 3, including the additional information submitted to the NRC through May 22, 2002, the staff identified 15 issues that remained open at the time this report was published previously as an SER with Open Items on September 16, 2002. An issue was considered open if Exelon had not presented a sufficient basis for its resolution. Each Open Item was assigned a unique identifying number, which identified the section in this report in which the Open Item was described. For example, Open Item 3.0-1 was discussed in Section 3.0 of this report. By letters dated November 26 and December 19, 2002, January 14, and January 29, 2003, the applicant responded to these Open items. The staff reviewed the responses and has closed all of the Open Items. The base for closing the Open Items can be found in the following Sections: 2.3.2.7.2, 2.3.3.8.2, 2.3.3.9.2, 2.3.3.18.2, 2.3.3.19.2, 2.4.7.2, 3.0.3.6.2, 3.0.3.11.2, 3.0.3.16.2, 3.1.3.2.1, 3.6.1.2.1, 3.6.1.2.2, and 4.5.2.

1.5 Summary of Confirmatory Items

As a result of the staffs’ review of Exelon’s application for license renewal, including the additional information and clarifications submitted subsequently, the staff identified the confirmatory items listed below, as of the time this report was published previously as an SER with Open Items on September 16, 2002. Confirmatory Items were those for which Exelon had not yet provided adequate documentation. In addition, confirmatory items may include significant matters that need to be considered as possible license conditions or technical specification requirements, depending on the form of the resolution. Each Confirmatory Item was assigned a unique identifying number, which identified the section in this report in which the Confirmatory Item was described. For example Confirmatory Item 3.0-1 was discussed in Section 3.0 of this report. By letters dated November 26 and December 19, 2002, January 14, and January 29, 2003, the applicant responded to these Confirmatory Items. The staff reviewed the responses and has closed all the Confirmatory Items. The base for closing the Confirmatory Items can be found in the following Sections: 3.0.3.3.2, 3.0.3.11.2, 3.0.3.13.2, 3.0.3.14.3, 3.0.3.17.2, 3.0.3.19.2, 3.0.3.20.3, 3.0.4, 3.2.1.2.2, 3.6.1.2.2, 3.6.2.2.2, 4.1.2, 4.1.3, 4.2.1.2, 4.2.3.2, 4.2.4.2 and 4.3.2.

1.6 Summary of Proposed License Conditions

As a result of the staffs' review of Exelon's application for license renewal, including the additional information and clarifications submitted subsequently, the staff identified 4 license conditions. The first license condition requires the applicant to include the UFSAR Supplement in the next UFSAR update required by 10 CFR 50.71 (e). The second license condition requires that, prior to operation in the renewal term, the applicant will notify the NRC of its decision to implement either the staff-approved reactor vessel integrated surveillance program, or a plant-specific program, and provide the appropriate revision to the UFSAR Supplement summary descriptions of the program. The third license condition requires that the future inspection activities identified in the UFSAR Supplement be completed before the beginning of the extended period of operation. The fourth license condition requires that, prior to operation in the renewal term, the applicant will notify the NRC of its decision to implement either the staff-approved core shroud inspection and evaluation guidelines program, or a plant specific program, and provide the appropriate revision to the UFSAR supplement summary description of the program.

2 STRUCTURES AND COMPONENTS SUBJECT TO AN AGING MANAGEMENT REVIEW

This section of the SER describes the staff's review of the methodology used by Exelon to implement the scoping and screening requirements of 10 CFR Part 54 (the license renewal rule), and the staff's evaluation of Exelon's scoping and screening results.

By letter dated July 2, 2001, Exelon submitted its request and application for renewal of the operating licenses for the Peach Bottom Atomic Power Station, Units 2 and 3. As an aid to the NRC staff during the review, Exelon provided evaluation boundary drawings that identify the functional boundaries for systems and components within the scope of license renewal. These evaluation boundary drawings are not part of the license renewal application.

On January 23 and March 12, 2002, the staff issued requests for additional information (RAIs) regarding the applicant's methodology for identifying structures, systems, and components (SSCs) at Peach Bottom that are within the scope of license renewal and subject to an aging management review (AMR) and regarding the results of the applicant's scoping and screening process. On February 28 and May 22, 2002, the applicant provided responses to the RAIs.

2.1 Scoping and Screening Methodology

2.1.1 Introduction

Title 10 of the Code of Federal Regulations, Part 54 (10 CFR Part 54), "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," Section 54.21, "Contents of Application—Technical Information," requires that each application for license renewal contain an integrated plant assessment (IPA). The IPA must list and identify those structures and components (SCs) that are subject to an AMR from among the systems, structures, and components (SSCs) that are within the scope of license renewal in accordance with 10 CFR 54.4.

In Section 2.1, "Scoping and Screening Methodology," of the Peach Bottom Atomic Power Station (PBAPS), Unit 2 and 3, license renewal application (LRA), the applicant described the scoping and screening methodology used to identify SSCs that are within the scope of license renewal and SCs that are subject to an AMR. The staff reviewed the applicant's scoping and screening methodology to determine if it met the scoping requirements set forth in 10 CFR 54.4(a) and the screening requirements set forth in 10 CFR 54.21. In developing the scoping and screening methodology, the applicant considered the requirements of the rule, the statements of consideration for the rule, and the guidance provided by the Nuclear Energy Institute (NEI), "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 - The License Renewal rule," Revision 3, March 2001 (NEI 95-10). The applicant also considered the NRC staff's correspondence with other applicants and the NEI regarding the development of this methodology.

2.1.2 Summary of Technical Information in the Application

In LRA Sections 2.0 and 3.0, the applicant provides the technical information required by 10 CFR 54.21(a). In LRA Section 2.1, "Scoping and Screening Methodology," the applicant describes the process used to identify the SSCs that meet the license renewal scoping criteria under 10 CFR 54.4(a) and the process used to identify the SCs that are subject to an AMR in accordance with 10 CFR 54.21(a)(1).

LRA Sections 2.2 "Plant Level Scoping Results," 2.3 "Scoping and Screening Results: Mechanical," 2.4 "Scoping and Screening Results: Structures and Component Supports," and 2.5 "Scoping and Screening Results: Electrical and Instrumentation and Controls," further describe the process that the applicant used to identify the SCs that are subject to an AMR. LRA aging management review results (Section 3.0), contains information on aging management of the reactor coolant system (Section 3.1), engineered safety features systems (Section 3.2), auxiliary systems (Section 3.3), steam and power conversion systems (Section 3.4), structures and component supports (Section 3.5), and electrical and instrumentation and controls (Section 3.6). Chapter 4 of the LRA, "Time-Limited Aging Analyses," contains the applicant's evaluation of time-limited aging analyses.

2.1.2.1 Scoping Methodology

Scoping has been performed to identify the plant systems and structures within the scope of the license renewal rule. In LRA Section 2.1.2, "Scoping Methodology," the applicant discussed the scoping methodology as it related to the safety-related criteria in accordance with 10 CFR 54.4(a)(1), the non-safety-related criteria in 10 CFR 54.4(a)(2), and the scoping criteria in 10 CFR 54.4(a)(3) for regulated events.

2.1.2.1.1 Safety-Related Systems, Structures, and Components

Figure 2.1-1 of the LRA presents a broad overview of the scoping and screening process and identifies the basic steps. Some steps are previously completed evaluations and form part of the current licensing basis (CLB). These steps are documented in the PBAPS maintenance rule (MR) system scoping results, the component record list (CRL), the updated final safety analysis report (UFSAR), and other plant design documentation which is consistent with NUREG-1800, "Standard Review Plan for Review of License Renewal Application for Nuclear Power Plants." The previously completed MR scoping evaluations were performed on a system basis for each mechanical and electrical system identified in the CRL. The scoping and screening methodology used by Exelon is described in Sections 2.1.1, 2.1.2, and 2.1.3 of the LRA.

With respect to the safety-related criteria in 10 CFR 54.4(a)(1), the applicant stated that the SSCs within the scope of license renewal include safety-related SSCs, which are those relied on to remain functional during and following design basis events (as defined in 10 CFR 50.49(b)(1)(i)) to ensure the following functions: (i) the integrity of the reactor coolant pressure boundary; (ii) the capability to shut down the reactor and maintain it in a safe shutdown condition; or (iii) the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the guidelines in 10 CFR 50.34(a)(1), 10 CFR 50.67(b)(2), or 10 CFR 100.11, as applicable.

The applicant relied on the UFSAR, plant design drawings, MR bases documents, plant equipment lists, the CRL, design baseline documents (DBDs), and other design documents from previously completed evaluations in the CLB, such as the results of the MR system scoping, to identify SSCs and their functions in accordance with the criteria in 10 CFR 54.4(a)(1). The CRL is a verified and controlled database of plant systems and equipment (e.g., mechanical and electrical systems and components). The CRL gives the quality classification of each component and is used to identify the safety-related components in the plant. The UFSAR includes information on the plant, presents the design bases and the limits on the plant's operation, presents the safety analyses of the SSCs and of the facility as a whole, and identifies the intended functions of structures. DBDs are comprehensive system-level documents that provide the design bases and include system functions, controlling parameters, and design features for various operating and accident conditions. In addition, DBDs discuss the regulatory requirements, commitments, codes and standards, and system configuration changes that are reflected in the design basis of the system. The evaluation against license renewal scoping criterion 54.4(a)(1) for mechanical and electrical systems is taken from the evaluation against the corresponding MR scoping criterion described in the LRA. The applicant then performed additional scoping activities to identify systems and structures within the scope of license renewal. For structure-level scoping, a comprehensive list of plant structures to be evaluated for license renewal scoping was produced from the MR bases documentation, the UFSAR and other plant design documentation. Seismic Class I structures were included within the scope of license renewal under scoping criterion 10 CFR 54.4(a)(1). Structural component listings were downloaded from the CRL and added to the license renewal database. Certain types of structural components and commodity items are not identified in the CRL (e.g., equipment pads and pedestals and equipment supports). Such components and commodity items were identified by review of design drawings and plant walkdowns and added to the license renewal database. Some structural components may also be listed as components of mechanical and electrical systems in the CRL.

The scoping results are documented, reviewed, and approved on a license renewal scoping form and entered in the license renewal database. The format of the scoping form is defined in Exhibit LR-C-14-3 of PBAPS procedure LR-C-14, "License Renewal Process." A scoping form is prepared for each system and structure and includes references to the applicable UFSAR sections, design drawings, and DBDs. The form also includes answers to several scoping questions related to system intended functions, applicable supporting systems, and whether any components were realigned into or out of the system (the system boundary realignment methodology is discussed in Section 2.1.2.1.4 of this report). The scoping form is generated as a report from the license renewal database into which the scoping data is entered during the review process. Boundary drawings for the various disciplines in the form of marked-up piping and instrumentation drawings (P&IDs), electrical single-line drawings, and site plan drawings were prepared to identify the major mechanical systems, electrical systems, and plant structures within the scope of license renewal. The documents are also reviewed and approved by both the license renewal team and PBAPS system managers.

2.1.2.1.2 Non-safety-related Systems, Structures, and Components

With respect to the non-safety-related criteria in 10 CFR 54.4(a)(2), the applicant stated, that a review of the UFSAR and other CLB documents has been performed to identify the non-safety-related and non-safety-related quality SSCs whose failure could prevent satisfactory accomplishment of any of the functions identified in 54.4(a)(1)(i), (ii), or (iii). Component listings for non-safety-related systems were downloaded from the CRL and reviewed to check for any safety-related components. This review assured that safety-related components associated with system interfaces are captured regardless of which system they were assigned to in the CRL. Any safety-related components found in non-safety-related systems were included in the license renewal database. The specific functions of such components were determined by review against the plant CLB on a case-by-case basis to identify the appropriate system and system intended functions the components are required to support, in accordance with 10 CFR 54.4(b). These component reviews are documented in the individual system scoping evaluation forms, and components are assigned to the appropriate in-scope system in the license renewal database. Component listings for systems in the scope of license renewal were also downloaded from the CRL and were included in the license renewal database. For systems in the scope of license renewal, the system intended functions are identified from the DBDs and the UFSAR.

For structures, the evaluation against license renewal scoping criteria 10 CFR 54.4(a)(2) is based on the UFSAR seismic classification which is either Class 1 or Class II. Seismic Class I structures are those required to remain functional and/or protect vital equipment and systems during and following postulated design basis events. Seismic Class II structures are those whose failure would not result in the release of significant radioactivity and would not prevent reactor shutdown. The applicant used the UFSAR and plant design drawings to generate a comprehensive list of plant structures. Walkdowns of non-safety-related mechanical and electrical systems were also performed by the applicant and the results reviewed to identify any structural components that needed to be included in the scope of license renewal. Any identified structural components were included with the structural system (System 70) in the license renewal database. The applicant also considered the structural integrity of non safety-related piping systems whose failure could adversely impact a safety-related SSC function, and the structural integrity of non-safety-related SSCs whose failure during a seismic event could cause an interaction with safety-related SSCs and potentially result in the failure of the safety-related SSCs to perform their intended function (Referred to as the “Seismic II/I” issue).

With respect to the structural integrity of non-safety-related piping, the PBAPS scoping process identified non-safety-related piping, which is an extension of the safety-related piping beyond the functional boundary (beyond the pressure boundary valves). In cases where the non-safety-related system is required to structurally support the safety-related piping, the non-safety-related piping segments and supports, up to the seismic anchor (or equivalent), are categorized as in-scope for license renewal. Certain types of structural components and commodity items are not identified in the CRL (e.g., equipment pads and pedestals and equipment supports). Such components and commodity items were identified by review of design drawings and plant walkdowns and added to the license renewal database. Mechanical and electrical systems may also include some structural components as items in the CRL. The non-safety-related mechanical and electrical system walkdowns were reviewed to identify any structural components that needed to be included in the scope of license renewal. Any such identified structural components were included with the structural system (System 70) in the license renewal database.

2.1.2.1.3 Regulated Events

The SSCs required to maintain compliance with 10 CFR 54.4(a)(3) were determined through a review of the UFSAR, various PBAPS position papers, licensing correspondence files, and other appropriate design documents. At PBAPS, the SSCs required to demonstrate compliance with the rule are associated with 10 CFR 50.48 (fire protection), 10 CFR 50.49 (environmental qualification), 10 CFR 50.62 (anticipated transient without scram), and 10 CFR 50.63 (station blackout). The scoping review form also includes questions related to fire protection, anticipated transient without scram, and station blackout to address license renewal scoping criterion 10 CFR 54.4(a)(3). For all other scoping criteria, the applicant reviewed all SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations.

Systems and structures that are in the scope of license renewal scoping criterion 10 CFR 54.4(a)(3) are identified by review of appropriate plant documentation. For 10 CFR 50.48 and 10 CFR 50.63, the review is documented in license renewal position papers. The reviewer uses the position papers and the CRL to answer the questions on the scoping and screening form. For 10 CFR 50.62, the required components are identified in the controlled CRL database. The equipment within the scope of 10 CFR 50.49 is identified by a controlled data field in the CRL and is addressed in LRA Section 4.4 under the time-limited aging analysis (TLAA) evaluations. For 10 CFR 50.61, no review is performed since it is not applicable to boiling water reactors.

2.1.2.1.4 System Boundary Realignment

A significant aspect of the licensee's scoping and screening methodology involved the use of system boundary realignment. Interfaces between systems were examined and realigned, as necessary, to ensure that interfacing components were associated with the appropriate system for license renewal. For example, a valve in an out-of-scope system that provides an isolation boundary interface with an in-scope system would be considered in the scope of license renewal. The valve is "realigned" to the in-scope system and the remainder of the out-of-scope system remains out-of-scope. Similar realignments are used to address out-of-scope systems that interface with the primary containment boundary. Electrical distribution systems interface with many systems, including many mechanical systems, and the interface point is often an electrical isolation device such as a fuse or circuit breaker. These electrical isolation devices are typically considered part of the mechanical system because their function is to provide electrical isolation of these systems. The applicant examined these interfaces to confirm interfacing components had been identified in the correct system for license renewal. For example, a fuse in an out-of-scope mechanical system that has an isolation boundary interface with an in-scope electrical system was considered in the scope of license renewal. The fuse was realigned to the in-scope electrical system, and the out-of-scope mechanical system remained out-of-scope.

In some cases, components were realigned to support specific intended functions. For example, at PBAPS the main steam isolation valves (MSIVs) are air-operated and require compressed gas to perform their intended function. These valves do not rely on the instrument air distribution system but instead utilize a dedicated instrument air accumulator. Accordingly, the MSIVs instrument air accumulators are required to support the intended function of the MSIVs. For purposes of system scoping, these instrument air accumulators were realigned from the instrument air system to the main steam system. System boundary realignment is described on page 2-5 of the LRA.

2.1.2.2 Screening Methodology

Following the determination of SSCs within the scope of license renewal, the applicant implemented a process for determining which SCs from among the SSCs within the scope of renewal would be subject to an AMR in accordance with the requirements of 10 CFR

54.21(a)(1). In Section 2.1.3, "Screening Methodology," of the LRA, the applicant discussed these screening activities for the various engineering disciplines as they related to the SSCs that are within the scope of license renewal.

2.1.2.2.1 Screening Methodology for Mechanical Components

The license renewal screening methodology identifies the passive, long-lived components subject to an AMR. Active-versus-passive determinations were made in accordance with 10 CFR 54.21(a)(1)(i) and the guidance of NEI 95-10. Long-lived components were identified in accordance with 10 CFR 54.21(a)(1)(ii) and the guidance of NEI 95-10. An AMR is required if the component performs an intended function without moving parts or without a change in configuration or properties (i.e., is passive) and if it is not subject to replacement on the basis of a qualified life or specified time period (i.e., is long-lived). Component-level intended functions were identified for the components requiring an AMR. The intended function of a component depends on the type of component and how it is relied on to support the intended function of the associated system or structure.

As part of the scoping review, component listings were downloaded from the CRL. For in-scope systems, the component listings were added to the license renewal database and used to assist in the development of boundary drawings. License renewal boundary drawings were prepared to identify the boundaries of systems in the scope of license renewal. Although not a requirement of the rule, the development of boundary drawings provided additional confirmation of correct system scoping. For mechanical systems, P&IDs were used to establish evaluation boundaries of systems and components in-scope. The downloaded component listings were added to the license renewal database that was used to assist in component screening. Certain types of components and commodity items such as piping, flex hoses, ventilation ductwork, and electrical cables and connectors, are not identified in the CRL. PBAPS procedure LR-C-14 includes a list of components not typically identified in the CRL. Such components and commodity items were identified by review of design drawings and plant walkdowns and added to the license renewal database.

As described above, CRL component listings were used to prepare boundary drawings and were also included in the license renewal database. For systems in the scope of license renewal, each system component was identified as in-scope, unless during the screening review and the development of boundary drawings it was determined that the component was not required to support the system intended functions. Components that do not support the system intended functions are not in the scope of license renewal and are identified as such in the license renewal database. Components that are not in the scope of license renewal are not shown within the license renewal scope boundary on the system boundary drawing. For example, the feedwater system is included in the scope of license renewal but the reactor feedwater pumps are not required to support any of the identified intended functions of the feedwater system and are not in the scope of license renewal. The reactor feedwater pumps are shown as not in the scope of license renewal in the license renewal database or on boundary drawings.

PBAPS screening form LR-C-14-6 is prepared for each system in the scope of license renewal. The form includes the component identification number and description, active/passive and long-lived determinations, component intended functions, and a reference to the applicable AMR. The screening results are entered in the license renewal database and are reviewed and approved by the license renewal team and the appropriate PBAPS system managers. The screening form also identifies any components that were realigned into the system. The form is generated as a report from the license renewal database into which the screening data is entered during the review process. For mechanical components, boundary drawings in the form of marked-up P&IDs were prepared, reviewed, and approved for the in-scope systems. The applicant's screening results are presented in Section 2.3 of the LRA.

2.1.2.2.2 Screening Methodology for Structural Components

The license renewal screening methodology identifies the passive, long-lived components subject to AMR. Active-versus-passive determinations were made in accordance with 10 CFR 54.21(a)(1)(i) and the guidance of NEI 95-10. Long-lived components were identified in accordance with 10 CFR 54.21(a)(1)(ii) and the guidance of NEI 95-10. Component-level intended functions were identified for the components requiring an AMR. The intended function of a component is based on the type of component and how it is relied on to support the intended function of the associated system or structure. Structures and components are screened to identify those that require an AMR in accordance with the requirements of 10 CFR 54.21 and component-level intended functions are identified.

PBAPS screening form LR-C-14-6 is prepared for each structure in the scope of license renewal. The form includes the component identification number and description, active/passive and long-lived determinations, component intended functions, and a reference to the applicable AMR. The screening results are entered in the license renewal database and are reviewed and approved by the license renewal team and the appropriate PBAPS system managers. The screening form also identifies any components that were realigned into the system. The form is generated as a report from the license renewal database into which the screening data is entered during the review process. A structural boundary drawing, in the form of a marked-up site plan, was prepared, reviewed, and approved to identify the plant structures in the scope of license renewal. The applicant's screening results are presented in Section 2.4 of the LRA.

2.1.2.2.3 Screening Methodology for Electrical Components

Systems for screening evaluations for license renewal were identified by using the CRL, which contains a comprehensive list of electrical systems. The CRL lists the component for each listed system and identifies the quality classification of each component. In addition, components and commodity items not identified in the CRL, such as electrical cables, were identified by review of design drawings and plant walkdowns and included in the license renewal database. For systems that had been determined to be within the scope of license renewal, the system components were identified as in-scope unless it was determined during the screening process that a component was not required to support the system intended function. Active/passive determinations were made in accordance with 10 CFR 54.21(a)(1)(i) and the guidance of NEI 95-10. Long-lived components were identified in accordance with 10 CFR 54.21(a)(1)(ii) and the guidance of NEI 95-10. For components determined to require an aging management review, the component-level intended functions were identified.

PBAPS screening form LR-C-14-6 is prepared for each electrical system in the scope of license renewal. The form includes the component identification number and description, active/passive and long-lived determinations, component intended functions, and a reference to the applicable AMR. The screening results are entered in the license renewal database and are reviewed and approved by the license renewal team and the appropriate PBAPS system managers. The screening form also identifies any components that were realigned into the system. The form is generated as a report from the license renewal database into which the screening data is entered during the review process. An electrical boundary drawing, in the form of a marked-up single line drawing was prepared, reviewed, and approved to identify the major electrical distribution systems within the scope of license renewal. The applicant's screening results are presented in Section 2.5 of the LRA.

2.1.3 Staff Evaluation

As part of the review of the applicant's LRA, the staff evaluated the scoping and screening activities described in Section 2.1, "Scoping and Screening Methodology"; Section 2.2, "Plant Level Scoping Results"; Section 2.3, "Scoping and Screening Results: Mechanical"; Section 2.4, "Scoping and Screening Results: Structures and Component Supports"; and Section 2.5, "Scoping and Screening Results: Electrical and Instrumentation and Controls" to ensure that the applicant describes a process for identifying SSCs that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(1), (a)(2), and (a)(3). In addition, the staff conducted a scoping and screening methodology audit at the Exelon corporate office December 4-7, 2001. The audit team reviewed implementation procedures and related documentation which describe the scoping and screening methodology implemented by the applicant. The focus of the audit was to ensure that the applicant had developed and implemented adequate guidance to conduct the scoping and screening of SSCs in accordance with the methodologies described in the LRA and the requirements of the rule.

2.1.3.1 Evaluation of the Methodology for Identifying Systems, Structures and Components Within the Scope of License Renewal

The audit team reviewed selected implementation procedures, position papers, and reports which describe the scoping and screening methodology implemented by the applicant. The documents reviewed are listed in Appendix B of this SER. The team found that the scoping and screening methodology reports and procedures were consistent with Section 2.1 of the LRA and were adequate to provide the applicant's staff with guidance on the scoping and screening implementation process to be followed during the LRA activities. In addition to the implementing procedures, the audit team reviewed supplemental design information, including the CRL (Q-list), DBDs, MR bases documentation, and license renewal position papers which were relied on by the applicant during the scoping and screening phases of the review. The team found these design documentation sources to be useful for ensuring that the initial scope of SSCs identified by the applicant was consistent with the CLB.

During the audit, the applicant further described the process used to incorporate plant design information into the LRA development process. The applicant referenced PBAPS procedures LR-C-14, "License Renewal Process," Revision 3; LR-C-14-3, "License Renewal System and Structure Screening Scoping Form"; Revision 3, and LR-C-14-6, "License Renewal Component Screening Form," Revision 4, to describe the process for developing the LRA application and incorporating the DBDs, MR bases information, CRL, and various license renewal position papers into the process. The procedures outline how these documents and other sources of information are used in the scoping methodology and give formal guidance on their use during the implementation phase. The applicant's engineering staff were cognizant of the requirements and use of these information sources during the scoping development phase of the LRA project.

The applicant provided the audit team with a description of the DBDs and how they were incorporated into the scoping and screening process. The audit team reviewed a sample of the DBDs for both safety-related and non-safety-related systems to better understand the approach implemented by the applicant to determine which SSCs would be initially placed in-scope for license renewal. The team found the DBD documents to provide a concise, well-documented discussion of both safety-related and non-safety-related systems and functions which had been assigned as a result of commitments to the NRC, including those for the Commission regulations identified under 10 CFR 54.4 (a)(3). Each DBD includes a detailed list of the sources of the information in system DBD content, including UFSAR and plant technical specification references, design inputs and system design baseline and evolution information, and non-plant-specific sources such as industry codes and standards, NUREGs, and NRC regulatory guides and information notices. The DBD documentation is controlled and maintained in accordance with the applicant's quality assurance program. The audit team determined that the DBDs were a reliable documentation source for determining system and structure functions during the scoping and screening process.

The applicant's program for the control and data input of the CRL is described in Exelon Nuclear Procedure NE-C-211, "CRL Control," Revision 9. The procedure describes the electronic component database which identifies each individual mark-numbered component and provides information on the component's safety classification and functions. During the review of the CRL information, the audit team reviewed a sample of the database screening results tables developed by the applicant to support the LRA program. The applicant designed a series of filters which enabled the LRA review engineers to sort through the equipment data system records and produce concise tables of component records based on either safety classification or specific functions of interest, such as environmental qualification and fire protection. The audit team determined that the CRL provided a useful tool for the applicant in developing the initial scope of SSCs for the program. During the staff's audit of the applicant's scoping and screening methodology, the staff requested that the applicant provide a detailed discussion of the basis of Figure 2.1-1, "Scoping and Screening Process Overview," of the LRA. In Request for Additional Information (RAI) 2.1.2-1, dated February 6, 2002, the staff asked Exelon to further describe the scoping and screening process for mechanical, structural, and electrical SSCs. On May 21, 2002, Exelon responded to the RAI. The RAI response provided a detailed description of each discipline and included a discussion of the applicant's methodology supporting the identification of systems, system scoping and boundary interfaces, component downloads from the CRL, system intended functions, and component screening.

With respect to the Seismic II/I issue, the scoping process involved a systematic review of the potential for non-safety-related SCs to interact with safety-related SC's. The UFSARs, licensing correspondence, and design basis documents were relied on in addressing these interactions. PBAPS Units 2 and 3 were not originally licensed for Seismic II/I; however, Seismic II/I concerns were addressed in response to Unresolved Safety Issue (USI) A-46, "Seismic Qualification of Equipment in Operating Plants," and considered for license renewal scoping. PBAPS position paper LR-P-005, "Identification of Non-Safety-Related SSCs Whose Failure Prevents Safety-Related SSCs From Fulfilling Their Safety-Related Function (Seismic II/I)," Revision 0, dated February 23, 2001, documents the results of the PBAPS CLB review performed to identify SSCs required to be included in the scope of license renewal pursuant to

10 CFR 54.4(a)(2). For Seismic II/I, PBAPS has chosen an area-based approach to scoping. Seismic Class II structural components, mechanical and electrical system supports, the foundation, and the anchorage of structures containing safety-related systems and components, including the items in the Safe Shutdown Equipment List credited for USI A-46 resolution, are included in the scope of license renewal.

By letters dated December 3, 2001, and March 15, 2002, the NRC sent a staff position to NEI which described areas to be considered and options the staff expects licensees to use to determine what SSCs meet the 10 CFR 54.4(a)(2) criterion. The letters provided specific examples of operating experience which identified pipe failure events, provided approaches the NRC considers acceptable to determine which piping systems should be included in-scope based on the 10 CFR 54.4(a)(2) criterion, and defines the staff's expectations for the evaluation of nonpiping SSCs to determine which additional non-safety-related SSCs are within-scope. The position states that applicants should not consider hypothetical failures but rather should base their evaluation on the plant's CLB, engineering judgement and analyses, and relevant operating experience. The staff position defines operating experience as all documented plant-specific and industry-wide experience which can be used to determine the plausibility of a failure. Documented operating experience includes NRC generic communications and event reports, plant-specific condition reports, industry reports, and engineering evaluations.

In RAIs 2.1.2-3 and 2.1.2-4, dated February 6, 2002 (which was consistent with the staff position described in the aforementioned letters), the staff asked Exelon to identify which option was used for non-safety-related piping systems which are not connected to safety-related piping but have a spatial relationship such that their failure could adversely impact on the performance of an intended safety function. The staff also asked Exelon to provide a discussion of the basis for the conclusion that the mitigative features are adequate to protect safety-related SSCs. On May 21, 2002, Exelon responded to the RAIs and stated that a review was performed to identify non-safety-related piping systems which are not connected to safety-related piping but have a spatial relationship such that their failure could adversely impact on the performance of an intended safety function. The applicant used its scoping methodology to identify those piping systems which were not in the scope of license renewal and which contained a fluid that could potentially adversely impact a safety-related system if the pressure boundary function degraded. These systems were designated as hazard systems. Then the spatial relationships were established to identify where these hazard systems could impact the safety-related SSCs. The spatial relationships were established based on plant drawings, the CRL, and plant walkdowns. The interactions were evaluated for credibility based on the spatial proximity of the hazard systems and safety-related SSCs. When the interaction was determined to be credible, the system was added to the scope of license renewal because it then satisfied the scoping criterion in 10 CFR 54.4(a)(2). Exelon also stated that an operating experience review of non-fluid-containing systems performed for the systems included in the scope of license renewal has shown no failures have occurred due to aging for the materials and environments. Examples of operating experience data included NRC Information Notices, Bulletins and Generic Letters, and relevant corrective action reports and work orders. Additionally, non-fluid-containing components cannot affect safety-related SSCs by leakage or spray.

The applicant stated in its May 21, 2002, response to the RAIs that the boundaries for six systems already in the scope of license renewal were expanded to include portions of the system that were non-safety-related. Also, 11 new systems were added to the scope of license renewal due to increased scope of criterion 10 CFR 54.4(a)(2). The non-safety-related components of these systems were found to be in spatial proximity to safety-related components such that an age-related failure of a non-safety-related component could impact the performance of an intended safety function. The response also stated that the component supports were already included in the scope of license renewal and that the applicant utilized the preventive option for this evaluation. This issue was also identified during the NRC Region I inspection of the PBAPS LRA, performed April 15-23, 2002, at the corporate office in Kennett Square, PA, and is further discussed in Section 2.3.3.19.2 of this SER.

During the NRC audit, the applicant provided the team with a detailed discussion on the development and implementation of the system boundary realignment process which is described in Section 2.1.2.1 of the PBAPS LRA and Project Level Instruction (PLI) PLI-001, “Peach Bottom License Renewal Project, Project Level Instruction,” Revision 0, dated April 18, 2001, “System Scoping and Realignment of CRL Components,” and LR-C-14, “License Renewal Process,” Revision 3. In RAI 2.1.2-2, dated January 23, 2002, the staff asked the applicant to further describe the realignment process. In the applicant’s response to the RAI dated February 28, 2002, the applicant provided a discussion of five general cases of interfacing system component realignment, developed by the applicant’s engineering staff, that provided guidance to the reviewer for identifying and documenting the realigned components to ensure that all SSCs in the CLB that meet the requirements of 10 CFR 54.4(a)(2) and 10 CFR 54.4(a)(3) have been identified and considered for inclusion in the scope of the LRA. Component realignments are performed in accordance with PLI-001 and the results are documented in the license renewal database and on the scoping and screening forms described in LR-C-14. The five cases of component realignment are as follows: Case 1- Components Associated with Containment Penetration; Case 2 - Interfaces Between In-scope and Out-of-scope Mechanical Systems; Case 3 - Interfaces Between In-scope Electrical and Out-of-scope Mechanical Systems; Case 4 - Components Shared Between In-scope and Out-of-scope Systems, and Case 5 - Components Required to Support Specific Intended Functions.

The rationale for the system boundary realignment was to associate system interfacing components with the appropriate license renewal system-level intended functions that they are required to support. This approach allows the appropriate systems and components to be included in the scope of license renewal based on the intended functions of the system, which is also consistent with MR system scoping approach. System safety classifications are documented in the MR scoping evaluations which were used for license renewal scoping. Boundary realignments and any resulting impacts on system level scoping or component screening were reviewed and discussed during the weekly license renewal team meeting. This review assured that the reviewers assigned to the interfacing systems were aware of and concurred with the final boundary alignments. The system boundary realignment process can be considered a recategorization of existing components for license renewal purposes without changes to the CLB or physical changes to the plant. From a system perspective, the out-of-scope systems are not safety-related in the PBAPS CLB. System boundary interfaces were examined to ensure that interfacing components required to support an in-scope system intended function were associated with the appropriate system for license renewal. The CRL component assignments within systems are often established based on the operational system functions and not necessarily based on the functions performed during design basis events. As a result, some non-safety-related systems at PBAPS include safety-related components associated with the system’s interface to a safety-related system. Non-safety-related systems that do not meet any of the license renewal scoping criteria from 10 CFR 54.4(a)(1), (2), or (3) are not included in the scope of license renewal. Component listings for these systems were reviewed to check for any safety-related components. This review assured that components that interfaced with safety-related systems are included in the scope of license renewal regardless of which system they were assigned to in the CRL. Any safety-related components found in non-safety-related systems were included in the license renewal database. The specific functions of such components were reviewed against the plant CLB on a case-by-case basis to determine the system and system intended functions they are required to support. These component reviews are documented in the individual system scoping evaluation forms and in the license renewal component database.

The scoping criterion of 10 CFR 54.4(a)(3) requires an evaluation to identify SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with specific Commission's regulations. The scoping review form includes several questions to address the criterion of 10 CFR 54.4(a)(3). Systems that are in-scope are identified by review of appropriate plant documentation. For 10 CFR 50.48 (fire protection) and 10 CFR 50.63 (station blackout), the staff reviewed license renewal position papers LR-P-002, Revision 1, dated September 6, 2001, and LR-P-003, Revision 0, dated October 6, 2000, respectively. The purpose of the position papers is to identify the systems and structures required to demonstrate compliance with the Commission's regulations.

As a result of the staff's issuance of the latest interim staff guidance (ISG) on Station Blackout, dated April 1, 2002, the applicant revised the scope of SSCs necessary to conform with the ISG position. Discussions on the expanded scoping and AMR results for the Station Blackout for electrical equipment are provided in Section 2.5 and 3.6 of this SER while structural components are provided in Sections 2.4.6 and 3.5.3 of this SER. The staff also reviewed scoping and screening forms for standby liquid control, instrument air, fuel pool cooling and cleanup, and feedwater controls and piping. The reviewer used the position papers and the CRL to answer the questions related to 10 CFR 54.4(a)(3). For 10 CFR 50.62 (ATWS), the required components are identified in the controlled CRL database. Equipment within the scope of 10 CFR 50.49 (environmental qualification) is identified by a controlled data field in the CRL and is addressed in LRA Section 4.4 under the TLAA evaluations. Components included in the PBAPS environmental qualification program are in-scope for license renewal. The results of system scoping are documented, reviewed, and approved on license renewal scoping form LR-C-14-3, which is prepared for each system. The form includes references to the applicable UFSAR sections, design drawings and DBDs. The form also includes answers to the scoping questions, system intended functions, applicable supporting systems, and whether any components were realigned into or out of the system. The scoping form is generated as a report from the license renewal database into which the scoping data is entered during the review process.

The staff concluded that the applicant's scoping methodology for identifying the SSCs within the scope of license renewal was consistent with the requirements of 10 CFR 54.4.

2.1.3.2 Evaluation of the Methodology for Identifying Structures and Components Subject to an Aging Management Review

The staff reviewed the methodology used by the applicant to identify mechanical, structural, and electrical components within the scope of license renewal that were subject to further aging management evaluation. The applicant provided the staff with a detailed discussion of the processes used by each engineering discipline, including the screening methodology, and a sample of the screening results reports for a selected group of safety-related and non safety-related systems. Following the determination of SSCs within the scope of license renewal, the applicant implemented a process for determining which SCs from among the SSCs within the scope of license renewal were subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). In developing the screening methodology, the applicant considered the rule and the guidance provided in NEI 95-10. In the development of this methodology, the applicant also considered NRC staff correspondence with other applicants and with NEI. The applicant discusses these screening activities in the various engineering disciplines as they relate to the SSCs that are within the scope of license renewal in LRA Section 2.1.3, "Screening Methodology."

The staff reviewed the methodology used by the applicant to identify and list the mechanical components subject to an AMR as well as the applicant's technical justification for this methodology. The staff also examined the applicant's results from the implementation of this methodology by reviewing an overview of the mechanical systems identified as being within the scope, a sample of evaluation boundaries drawn within those systems, the resulting components determined to be within the scope of the rule, the corresponding component-level intended functions, and the resulting list of mechanical components subject to an AMR. The methodology for identifying mechanical components within the scope of the rule included both mark-numbered components (i.e., components identified in the applicant's electronic component database) and non-mark-numbered components. For the mark-numbered components, the individual components were identified and reviewed. For the non-mark numbered components, the components were categorized by component groups such as tubing and hoses. These component groups were then evaluated as part of the system screening table development. Based on the process review and sampling of the process implementation, the audit team concluded that the screening methodology would adequately support screening of mechanical components and documentation of the process.

For structural components, the applicant performed a review to determine which in-scope components would be subject to an AMR. During the audit of the applicant's renewal scoping and screening process, the staff also examined the applicant's results from the implementation of this methodology by reviewing the structural components identified as being within the scope, the corresponding intended functions, and the resulting list of structural components subject to an AMR. The staff performed a detailed review of the scoping and screening methodology process for System 70, "Structures, Structural Commodities, and Seals," dated July 26, 2001." During discussions with the applicant, it was determined that a plant walkdown as well as a review of the UFSARs was conducted to initially identify Seismic Class I and II structures. The process included initiating the appropriate scoping and screening forms for System 70 structures. The team reviewed the scoping forms for the reactor building, turbine building, and control room complex. The forms included pertinent supporting technical information such as DBD number, UFSAR section, drawing numbers, intended system functions, supporting systems, applicable boundary realignment, and system boundary drawing numbers. The staff reviewed the documents to obtain reasonable assurance that the scoping and screening process, as implemented and documented, was consistent with the appropriate supporting technical information for the systems reviewed. The staff also reviewed a sample of the P&IDs and performed an overview of portions highlighted as in-scope and verified that the applicable portions were included. This drawing review also included a sample of system drawings for mechanical and electrical systems where components had been realigned into System 70. The team also reviewed the screening form for System 70 which identified those components within the scope of license renewal. This list also identified whether the component is included in the CRL for license renewal. The applicant's review identified 12 structures within the scope of license renewal (Table 2.2-2 of the LRA). The tables in Section 3.5, "Aging Management of Structures and Component Groups," of the LRA, provide the results of aging management reviews for structural component groups in each of the 12 structures within the scope of license renewal and the five structure commodity groups. Based on the process review and sampling of the process implementation, the audit team concluded that the screening methodology would adequately support screening of structural components and documentation of the process.

The staff also evaluated the implementation of this methodology by reviewing the list of electrical components subject to an AMR. Systems for screening evaluations for license renewal were identified by using the CRL, which contains a comprehensive list of electrical systems and contains a component list for each listed system and identifies the quality classification of each component contained in the listed system. In addition, components and commodity items not identified in the CRL, such as electrical cables, were identified by review of design drawings and plant walkdowns and included in the license renewal database. For systems that had been determined to be within the scope of license renewal, the system components were identified as in-scope unless it was determined during the screening process that the component was not required to support the system intended function. Active/passive determinations were made in accordance with 10 CFR 54.21(a)(1)(i) and the guidance of NEI 95-10. Long-lived components were identified in accordance with 10 CFR 54.21(a)(1) and the guidance of NEI 95-10. For components determined to require AMR, the component-level intended functions were identified.

The results of the screening process were documented on screening forms for the appropriate system. The audit team reviewed the screening forms for the control rod drive (CRD) system. The forms indicated that certain components had been realigned to the 4kV system. The screening form for the 4kV system indicated receipt of the components from the CRD system and, in addition, listed the component numbers, component description, whether the component was passive, whether the component was long-lived, and the component intended function. Based on the process review and sampling of the process implementation, the audit team concluded that the screening methodology would adequately support screening of electrical components and documentation of the process.

2.1.4 Conclusions

The staff reviewed of the information presented in Section 2.1 of the LRA, the supporting information in the PBAPS UFSAR, the information presented during the scoping and screening audit and inspection, and the applicant's responses to the staff's RAIs, as discussed above. The staff concluded that the applicant's scoping and screening methodology, including its supplemental 10 CFR 54.4(a)(2) review which brought additional non safety-related piping segments and associated components into the scope of license renewal was consistent with the requirements of the rule and the staff's position on the treatment of non safety-related SSCs. On the basis of its review, the staff concludes there is reasonable assurance that the applicant described an adequate scoping and screening methodology to identify SSCs within the scope of the license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.2 Plant-Level Scoping Results

2.2.1 Introduction

This section describes the staff's evaluation of LRA Section 2.2, "Plant Level Scoping Results." The license renewal rule, 10 CFR Part 54, requires the applicant to provide the results of an integrated plant assessment (IPA) of the SSCs for which an AMR is required. The statements of consideration (60 FR 22478) for the rule indicate that an applicant has the flexibility to determine this set of SSCs, provided the set of SSCs encompasses those for which the Commission has determined an AMR is required. Accordingly, the staff focused its review on verifying that the implementation of the applicant's methodology, as discussed in Section 2.1 of this SER, did not result in the omission of SCs subject to an AMR in accordance with 10 CFR 54.21 (a)(1). Therefore, the staff performed the following two-step evaluation:

- The staff determined whether the applicant properly identified the SSCs within the scope of license renewal in accordance with 10 CFR 54.4. As described in more detail below, the staff reviewed selected SSCs the applicant did not identify as falling within the scope of license renewal to verify whether they have any intended functions that fall within the scope of license renewal.

- The staff then determined, in accordance with 10 CFR 54.21 (a)(1), whether the applicant properly identified the SCs that are subject to an AMR from among the SSCs that were previously identified as being within the scope of license renewal in accordance with 10 CFR 54.4. More specifically, and as described in more detail below, the staff reviewed selected SCs that the applicant identified as being within the scope of license renewal to verify whether the applicant properly identified the SCs that are subject to an AMR, including whether they perform their intended functions, as described in 10 CFR 54.4, without moving parts or without a change in configuration or properties and are not subject to replacement based on a qualified life or specified time period. To determine whether the applicant identified all of the SCs that are subject to an AMR, the staff reviewed SSCs that the applicant had not identified as subject to an AMR.

The staff reviewed the results of the scoping and screening effort to determine if there is reasonable assurance that the applicant identified and listed all plant level systems and structures within the scope of license renewal in accordance 10 CFR 54.4 and subject to an AMR in accordance with 10 CFR 54.21(a)(1).

2.2.2 Summary of Technical Information in the Application

The staff evaluated components and commodities associated with all systems and structures in Sections 2.3 through 2.5 of the Peach Bottom LRA. In LRA Sections 2.3.1, "Reactor Coolant System," 2.3.2, "Engineered Safety Features Systems," 2.3.3, "Auxiliary Systems," and 2.3.4, "Steam and Power Conversion Systems," the applicant described the mechanical systems and components within the scope of license renewal and subject to an AMR, based on the applicant's license renewal scoping and screening methodology as described in Section 2.1 of this SER.

Structures that support, or provide shelter and protection for, the operation of other systems are presented in Section 2.4 of the LRA. Some structural components were treated as bulk commodity items common to various systems and structures. These commodity items are described in LRA Sections 2.4.13, "Component Supports," 2.4.14, "Hazard Barriers and Elastomers," 2.4.15, "Miscellaneous Steel," 2.4.16, "Electrical and Instrumentation Enclosures and Raceways," and 2.4.17, "Insulation."

Electrical systems and I&C systems that support the operation of both safety- and non-safety-related systems and structures are presented in Section 2.5 of the LRA. Electrical and I&C components are all treated using a bulk commodity approach.

2.2.2.1 Systems, Structures, and Components Within the Scope of License Renewal

In Sections 2.2 through 2.5 of the LRA, the applicant describes the SSCs within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 54.21 (a)(1), respectively. As described in Section 2.1, scoping and screening of mechanical components was performed using a systems approach in conjunction with a controlled database called the component record list (CRL). The CRL uniquely identifies most of the mechanical components at Peach Bottom and provides a link to the associated system. The applicant identified those mechanical components not assigned unique component numbers in the CRL by evaluation of design drawings and documents and by plant walkdowns. These items were treated as commodities for the purposes of license renewal. The CRL database was later updated to include commodity items and to add a field to each component record to identify the components/commodities within the scope of license renewal.

Table 2.2-1 of the LRA presents the results of the applicant's plant-wide scoping of mechanical systems at Peach Bottom. The table indicates whether the intended functions of a given system are needed to satisfactorily accomplish any of the functions in 10 CFR 54.4(a)(1), (2), and (3). Components of non-safety related systems meeting the requirements of 10 CFR 54.4(a)(2) are considered within the scope of license renewal.

Seismic Class I structures and structural components are considered safety-related; therefore, all Seismic Class I structures and structural components requiring an aging management review are within the scope of license renewal. Plant structures and structural components are not uniquely identified in the Peach Bottom CRL. As a result, the UFSAR, engineering drawings, and plant walkdowns were used to identify structures and structural components that are within the scope of license renewal.

The turbine building, the SBO structure, and certain yard structures (including the condensate storage tanks and foundations) are Seismic Class II structures that were included in the scope of license renewal. For example, the main control room complex is a Seismic Class I structure located in the central portion of the Seismic Class II turbine building. These structures support and protect safety-related equipment and equipment required for compliance with 10 CFR 54.4(a)(3) for regulated events.

Some common structural features and components (such as component supports, insulation, hazard barriers, and elastomers and miscellaneous steel) were considered generically and assigned to a commodity group for scoping purposes. Table 2.2-2 of the LRA lists the scoping results for structures. In addition, electrical and I&C system components at Peach Bottom were considered generically and treated as commodity groups. Scoping results for the electrical and I&C systems are listed in Table 2.2-3.

As discussed in LRA Section 2.1.2, the applicant chose to scope and screen components that interface with or support in-scope mechanical and electrical systems with the system considered most appropriate for license renewal. In the Peach Bottom LRA, the applicant refers to this process as “system boundary realignment.” These component realignments modified the traditional nomenclature and system boundaries defined by the Peach Bottom UFSAR, CRL, and piping and instrumentation drawings (P&IDs), but did not change the actual location of any components or physical configuration of any systems. The comment column of LRA Table 2.2-1 identifies the most significant system boundary realignments performed by the applicant during the Peach Bottom scoping and screening process.

For example, if a valve in an out-of-scope system provided an isolation boundary interface with an in-scope system, that valve was realigned, i.e., recategorized as part of the in-scope system for the purpose of license renewal. Similar component realignments were used for out-of-scope systems that support specific intended functions. For example, at Peach Bottom, the main steam isolation valves are air-operated valves that require compressed gas to perform their intended function. These valves do not rely on the instrument air distribution system, but instead utilize a dedicated instrument air accumulator. Accordingly, the main steam isolation valve (MSIV) instrument air accumulators are required to support the intended function of the MSIVs. For purposes of system scoping, these instrument air accumulators were realigned from the instrument air system to the main steam system. The applicant stated that the realignment of components was performed to simplify the mechanics of the Peach Bottom scoping and screening process, as this procedure minimized the number of systems and components that had to be manipulated and tracked in the applicant’s license renewal computer database.

As an attachment to a letter dated July 2, 2001, The applicant supplied license renewal drawings to the staff. These drawings help identify the components and boundaries of systems within the scope of license renewal but are not considered a part of the LRA. In addition, as these drawings are basically marked-up P&IDs, they do not identify many small mechanical and electrical components. However, the applicant has stated that SSCs within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.21(a)(1) will be identified in the Peach Bottom license renewal database in an auditable and retrievable manner in accordance with the requirements of 10 CFR 54.37.

2.2.2.2 Systems and Structures Not Within the Scope of License Renewal

As stated above, LRA Section 2.2 presents the scoping results for the various Peach Bottom systems and structures. LRA Tables 2.2-1, 2.2-2, and 2.2-3 list the systems and structures, and identify whether the systems and structures are considered within the scope of license renewal. The applicant originally listed 70 mechanical systems in LRA Table 2.2-1, 37 of which were not considered within the scope of license renewal. In response to staff RAIs (discussed in Section 2.1.3), and Open Item 2.3.3.19.2-1(discussed in Section 2.3.3.19.2-1), the following additional 11 systems were later brought within the scope:

- service water system
- reactor building closed cooling water system

- reactor water cleanup system
- chilled water system
- water treatment system
- plant equipment and floor drain system
- process sampling system
- auxiliary steam system
- condensate transfer
- refueling water storage and transfer
- torus water cleanup system

In response to open item 2.3.3.19.2-1, by letter dated November 26, 2002, an additional system, the post accident sampling system was brought within the scope of license renewal. The next section documents the staff evaluation of whether the applicant IPA omitted Peach Bottom systems and structures that meet the criteria of 10 CFR 54.4 and therefore should have been included within the scope of license renewal.

2.2.3 Staff Evaluation

In LRA Section 2.1, the applicant describes its IPA methodology for identifying the SCs that are within the scope of license renewal and subject to an AMR. An IPA methodology typically consists of a review of all plant SSCs to determine those that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4. From those plant SSCs that are within the scope of license renewal, the applicant will identify and list those SCs that perform their intended function without moving parts, or without a change in configuration or properties and that are not replaced based on a qualified life or specified time period. The staff reviewed the applicant's scoping and screening methodology, and provided its evaluation in Section 2.1 of this SER. The applicant documented the implementation of that methodology in Sections 2.2 through 2.5 of the LRA.

To ensure that the scoping and screening methodology described in Section 2.1 of the LRA was implemented properly and identified the SCs that are subject to an AMR, the staff performed the following additional review. The staff sampled the contents of the UFSAR based on the listing of systems and structures in Tables 2.2-1 and 2.2-2 of the LRA to identify systems or structures that may have intended functions that meet the scoping requirements of 10 CFR 54.4 but that the applicant does not include within the scope of license renewal. The staff selected several systems and structures to determine how the scoping and screening process was performed to ensure that structures and components (SCs) and their intended functions that need to be in the scope of license renewal are captured in a consistent manner. In a letter to the applicant dated October 30, 2001, the staff requested additional information about how SCs of the (1) battery and emergency switchgear ventilation system, (2) reactor building structure, (3) residual heat removal system, and (4) fuel handling system the SCs' intended functions are captured in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

In a letter dated November 16, 2001, the applicant's response to the staff's RAI included an explanation of the following activities which ensure SCs and their intended functions are captured in a consistent manner:

- identification of plant systems and structures
- identification of system and structure scoping

- identification of system boundary interfaces
- identification of system intended functions
- identification of structure and component screening
- LRA documentation

The applicant stated that the battery and emergency switchgear ventilation system included components which were realigned from the non-safety-related instrument air system that support the battery and emergency switchgear ventilation system. These instrument air components are included in the license renewal database and were organized into component groups and evaluated in the AMR for the gas environment. However, Table 2.3.3-9 did not include the component groups in the gas environment. The applicant's response to the staff RAI revised Table 2.3.3-9 by including the component groups and gas environment required to complete an adequate AMR of the components in Table 2.3.3-9. The staff's review of the battery and emergency switchgear ventilation system is in Section 2.3.3.9 of this document.

The staff questioned the applicant's apparent omission of the spray function, spray nozzle component group (spray nozzles), and environment in Table 2.3.2-5 for the residual heat removal (RHR) system. The applicant, in its response to the staff's question dated November 16, 2001, stated that the containment spray mode of RHR utilizes headers located in the drywell and suppression chamber. The RHR system P&ID shows the ring headers, but does not specifically identify the spray nozzles. Further, the spray nozzles are not uniquely identified in the CRL database. Because the spray nozzles are not uniquely identified in the CRL, the applicant considered the spray nozzles as part of the containment spray ring header piping. The applicant's response to the staff RAI revised LRA Table 2.3.2-5 by including the spray nozzles in the component group and wetted gas environment required to complete an AMR of the components in Table 2.3.2-5. The staff's review of the RHR system is in Section 2.3.2.5.

<u>System Boundary Realignment</u>

As noted in Section 2.2.2.1, the applicant used a process it referred to as "system boundary realignment" to recategorize mechanical components for the purposes of license renewal. This process presented the staff reviewers with the need to correlate the UFSAR descriptions of systems and intended functions with the systems as described in the LRA. Consequently, the staff expended additional resources to overcome the confusing differences between the system and component nomenclature in the LRA, the UFSAR, and other CLB documents. Another side effect of the realignment process was the elimination from the LRA of the discussion of the support functions provided by non-safety-related systems to safety-related systems within the scope of license renewal. This necessitated additional staff evaluations of the impact of component realignments to the boundary of safety-related systems within the scope from non-safety-related systems determined to be out of scope. However, specific components of the non-safety systems supporting safety-related systems are relied on to remain functional during or after a design basis event meeting the scope of the rule in §54.4(a)(2). Non-safety-related systems having components supporting safety-related systems are listed below:

Non-Safety-related Systems	Safety-Related Systems With Components Realigned to Non-Safety- Related System
Drywell Ventilation System	Primary Containment Isolation System
Primary Containment Leak Test System	Primary Containment Isolation System
Reactor Building Ventilation System	RHR System Core Spray System HPCI System RCIC System
Reactor Building Closed Cooling Water System	Primary Containment Isolation System
Reactor Water Cleanup System	Reactor Recirculation System Primary Containment Isolation System
Chilled Water System	Primary Containment Isolation System
Instrument Nitrogen System	Primary Containment Isolation System Main Steam System
Instrument Air System	Main Steam Safety-Grade Instrument Gas System Battery and Emergency Switchgear Ventilation System
Service Air System	Primary Containment Isolation System
Plant Equipment and Floor Drain System	Primary Containment Isolation System
Process Sampling System	Primary Containment Isolation System
Torus Water Cleanup System	Primary Containment Isolation System
Post-accident Sampling System	Primary Containment Isolation System
Traversing In Core Probe System	Primary Containment Isolation System

As a result of the applicant's system boundary realignment, the staff was unable to adequately review the implementation of the boundary realignment using the information presented in the Peach Bottom LRA. Therefore, the staff issued RAIs to the applicant on January 23 and March 12, 2002. The staff's RAI of January 23, 2002, asked the applicant to describe the realignment process and the rationale for its use. The staff's RAI of March 12, 2002, requested the applicant to provide (1) a brief description of each of these out-of-scope systems whose components were realigned to be in-scope, (2) a textual description of the types of components realigned, and (3) details regarding the intended function for each realigned component in the context of license renewal and how the realigned components met the criteria of 10 CFR 54.4(a)(1), (2), or (3). In addition, the RAI requested the applicant to provide a means to identify, in an unambiguous and traceable manner, the components realigned to systems within the scope of license renewal back to the out-of-scope systems. The applicant responded to this RAI by letter on May 22, 2002. The staff's RAI of January 23, 2002, questioned how the realignment was done and the March 12, 2002, RAI questioned the results of the realignment process as presented in the LRA in Sections 2.3 through 2.5. The applicant's response to the staff’s RAI, dated February 28, 2002, described the following five cases for system boundary realignment:

- Case 1: Components Associated with Containment Penetration - This case involves the realignment of components from non-safety-related systems that penetrate primary or secondary containment. The containment isolation valves and the interconnecting piping in non-safety-related systems are addressed in Section 2.3.2.3, Primary Containment Isolation System,” of the LRA.

- Case 2: Interfaces Between in-scope and out-of-scope Mechanical Systems - This case involves the examination of interfaces between safety-related and non-safety-related components to ensure that components from the non-safety systems needed to support safety systems were included within the scope of license renewal. The interfacing components are valves or dampers, and may also include attached segments of piping or ductwork.

- Case 3: Interfaces Between in-scope Electrical and out-of-scope Mechanical Systems - This case involves the evaluation of out-of-scope mechanical systems that interface with in-scope electrical distribution systems where isolation devices interface with the mechanical system. The electrical isolation devices protect the power source at the interface, and the interfaces were evaluated to ensure that components relied on to protect the electrical distribution system were included within the scope of license renewal. The isolation devices where realigned to the in-scope electrical system.

- Case 4: Components shared between in-scope and out-of-scope systems - This case only applies to the instrument air and instrument nitrogen systems where an interface exists between mechanical systems within the scope and out of the scope of license renewal. Boundary realignment of the mechanical system within the scope was completed because the CRL database identified the components as being shared with the non-safety-related system which is not in the scope.

- Case 5: Components required to support specific intended functions - This case involves interfaces between non-safety-related and safety-related systems within the scope of license renewal. Some non-safety-related systems have functional interface connections with safety-related systems that include components relied on to support a function of the safety-related system.

The staff had concerns with Cases 1, 4, and 5 with respect to the implementation of the applicant’s system boundary realignment. Case 1 involves the realignment of piping and components from the 12 non-safety-related systems identified in the above table to the primary containment isolation system. The applicant’s February 28, 2002, response to the staff’s RAI referenced the Generic Aging Lessons Learned (GALL) Report, Section V.C, “Containment Isolation Components,” which recognizes the potential for realignment of SCs from non-safety systems for the purposes of containment isolation as an acceptable practice meeting the requirements of license renewal. The staff notes that an applicant may also group like components into commodity groups and that the basis for grouping such SCs is determined by characteristics such as similar function, design, or materials of construction, similar aging management practices, or similar environments. Consequently, if an applicant uses commodity groups, the applicant has to provide the basis for the groups. However, the applicant’s discussion in Section 2.3.2.3, “primary containment isolation system,” does not mention the inclusion of SCs from the 12 non-safety systems nor does it provide an argument or basis for grouping those SCs as a commodity. The staff’s evaluation of the primary containment isolation system is provided in Section 2.3.2.3 of this document.

Case 4 involves the realignment of shared components of the instrument air and instrument nitrogen systems, which are non-safety-related, to (1) the safety grade instrument gas, (2) the backup instrument nitrogen to ADS, and (3) the battery and emergency switchgear ventilation system (BESVS). In the February 28, 2002, RAI response, the applicant stated that the plant design includes a safety grade backup source of compressed gas for the safety-related systems which share components with the above-mentioned non-safety-related systems. As previously stated, the staff’s evaluation of the BESVS is in Section 2.3.3.9 of this document. Also, the staff’s evaluations of other realignments involving the instrument air and nitrogen systems are in Section 2.3.3.12 (safety grade instrument gas), and 2.3.3.13 (backup instrument nitrogen to ADS), of this document.

Case 5 involves the realignment of piping and components of the reactor building ventilation system to the boundary of the RHR, core spray, high-pressure coolant injection, and RCIC systems. In the May 22, 2002, response to the staff’s RAI 2.2-1.2, the applicant stated that the cooling intended function for all components cooled by the emergency service water (ESW) system is included under the ESW system intended function of component cooling. Further, the HPCI, RCIC, RHR, and core spray system room coolers are cooled by the ESW system. The applicant also stated that the ESW system performs the room cooling function by providing cooling water to the room coolers and therefore the function of room cooling is not included as an intended function of the HPCI, RCIC, RHR, and core spray systems.

Because the components responsible for cooling were realigned to the HPCI, RCIC, RHR, and core spray systems, the system intended function of room cooling is removed from the scope of license renewal. The system intended function of room cooling meets the scope of the Rule in §54.4(a)(2). However, realignment of SCs to extend the boundary of HPCI, RCIC, RHR, and core spray obscures the room cooling function since the supported systems rely on the room coolers to remain functional before and after a design basis event but do not include room cooling as a system level intended function. The staff’s evaluations of the system boundary realignment of SCs are in Sections 2.3.2.5 (RHR), 2.3.2.1 (HPCI), 2.3.2.2 (core spray), and 2.3.2.4 (RCIC) of this document.

Non-Safety-related Systems Affecting Safety-Related Systems

The staff evaluated the applicant’s methodology for scoping SSCs meeting the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(2). The implementation of the methodology for the potential spatial interaction between non-safety and safety-related systems resulted in the expansion of systems boundaries for the following systems:

- reactor pressure vessel instrumentation system
- core spray system
- residual heat removal system
- fuel pool cooling and cleanup system
- control rod drive system
- radiation monitoring system

These systems were already within the scope of license renewal but the evaluation of non-safety-related portions of these systems boundaries determined that an age-related failure of the non-safety-related components could impact the performance of a safety-related SC resulting in a loss of a safety-related intended function. In addition, Section 2.2.2.2 of this document identifies non-safety-related systems that were brought within the scope of license renewal due to potential interactions with safety-related SCs. The staff's review of the systems brought into scope because of these potential interactions is in Section 2.3.3.19 of this document.

The applicant's response to the staff's RAIs provided in letters dated November 16, 2001, February 28, May 21, and May 22, 2002 provided the staff reviewers with adequate information to identify and cross-reference realigned components and intended functions from out-of-scope systems in the various LRA tables and descriptions for the Peach Bottom systems within the scope of license renewal.

2.2.4 Conclusions

On the basis of the staff's review of the information presented in Section 2.2 of the LRA, the supporting information in the Peach Bottom UFSAR, and the applicant's responses to the staff RAIs provided in letters dated November 16, 2001, and February 28, May 21, and May 22, 2002, the staff has reasonable assurance that the applicant has adequately identified the SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21 (a)(1), respectively. The NRC staff's detailed review of the SCs that are subject to an AMR is provided in Sections 2.3 through 2.5 of this SER.

2.3 System Scoping and Screening Results Mechanical

2.3.1 Reactor Coolant System

In Section 2.3.1, "Reactor Coolant System (RCS)," of the Peach Bottom Atomic Power Station, Unit 2 and 3, License Renewal Application (the LRA), Exelon (the applicant) described the systems, structures and components (SSCs) of the RCS that are subject to aging management review (AMR) for license renewal.

2.3.1.1 Reactor Pressure Vessel and Internals

2.3.1.1.1 Summary of Technical Information in the Application

As described in the LRA, the reactor pressure vessel is a vertical, cylindrical pressure vessel with hemispherical heads and is of welded construction. The cylindrical shell and bottom hemispherical head of the reactor vessel are fabricated of low alloy steel plate. The shell is clad on the interior with a stainless steel overlay, and the bottom head with an Inconel overlay. The major safety consideration for the reactor vessel is the ability of the vessel to function as a radioactive material barrier. The vessel also provides a floodable core volume, contains the moderator, and provides support for the reactor vessel internals.

The reactor vessel internals are installed to properly distribute the flow of coolant delivered to the vessel, to locate and support the fuel assemblies, and to provide an inner volume containing the core that can be flooded following a break in the nuclear system process barrier external to the reactor vessel.

The following intended functions of the reactor vessel are within the scope of license renewal:

Containment - The reactor vessel and internals provide a fission product and pressure barrier.

Physical support - The reactor vessel and internals provide vertical and horizontal support for the core and other reactor pressure vessel internal components.

Core cooling - The reactor vessel and internals provide a means to distribute coolant to the fuel assemblies located in the central region and in the periphery of the core.

Floodable volume - The reactor vessel and internals provide a means to flood the core to at least two-thirds core height following design basis accidents.

Table 2.3.1-1 of the LRA identified the component groups requiring aging management review. The following component groups were identified for the reactor pressure vessel and internals: top and bottom head, shell courses, flanges, closure studs and nuts, stabilizer bracket, support skirt, feedwater nozzle and other nozzles, nozzle safe ends (including core delta-P/SLC nozzle safe end), core spray attachments, jet pump riser brace attachments, shroud support attachment, other attachments, CRD stub tube penetrations, ICM housing and instrument penetrations, shroud, shroud support, access hole cover, core support plate, top guide, core delta-P/SLC line, core spray lines and core spray spargers, jet pump assemblies, orificed fuel support, CRD guide tube base, CRD housing stub tubes, CRD housing guide tubes, in-core housing guide tubes, and LPRM and WRNM dry tubes.

2.3.1.1.2 Staff Evaluation

The staff reviewed Section 2.3.1.1 of the LRA and relevant sections of the Peach Bottom UFSAR to determine whether there is reasonable assurance that the reactor pressure vessel and internals system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below. After completing the initial review, the staff requested by letter dated March 1, 2002, that the applicant to provide additional information on the reactor pressure vessel and internals. By the letter dated May 6, 2002, the applicant responded to staff's request for additional information (RAI) as discussed below.

In Table 3.1-1 of the LRA, spraying of the fuel assemblies following a LOCA was not identified as an intended function for the core spray spargers. The table also identified cracking as the only aging effect for the subject components. In RAI 2.3.1-1, the staff requested the applicant to address the following staff concerns:

a) The staff believes that adequate long-term core cooling following a LOCA can only be assured by retaining the original spray distribution over the core which was assumed for the CLB. In the safety evaluation report (SER) for the BWRVIP-18 report, the staff had concluded that when performing inspection of core spray spargers, all BWR plants need to be treated as "geometry-critical" plants. In addition, it is staff's understanding that the previous BWRVIP designations of "geometry-tolerant" plants have been rescinded and all plants are now considered to be "geometry-critical." Consequently, in order to assure adequate cooling of the uncovered upper third of the core, the core spray system must provide adequate spray distribution to all bundles in the core. It is also staff's understanding that leakage through sparger and piping cracks and repairs and potential blockage of spray nozzles must be considered in assessing the core spray distribution. As a result, the staff believes that it is essential that spraying water on the fuel assemblies in a pattern that was originally designed for the core be acknowledged as one of the license renewal intended functions for the spargers, and that the applicant's aging management activities be designed to provide a reasonable assurance that the original spray distribution will be preserved during the period of extended operation. The staff, therefore, requests the applicant to identify the spray distribution function as an intended function of the spargers within the scope of license renewal so that this function will be maintained during the license renewal period, and the applicant affirm that when performing inspection of core spray spargers, the Peach Bottom plants are inspected in accordance to the requirements for the "geometry-critical" plants, as required by the staff SER for the BWRVIP-18 report.

b) The staff believes that cracking of the core spray spargers is not the only aging mechanism which can degrade the spray distribution over the core following a LOCA, as Table 3.1-1 has suggested. Partial or full blockage of the spray holes due to repairs to reactor internals, by foreign objects (loose parts), and/or due to corrosion can also influence the core spray pattern. The staff understands that the applicant's ISI program (B.2.7) for the vessel internals is geared towards detecting cracking of the internals. The staff, therefore, requests the applicant to explain how it plans to detect other means of degradation of the spray pattern, as discussed above, when the B.2.7 program is used for managing the aging effects due only to cracking and loss of material, as stated in page B-64 of the LRA.

The applicant provided the following response:

a) The core spray sparger is identified in BWRVIP-06, "Safety Assessment of BWR Reactor Internals," as a safety-related component. BWRVIP-06 Section 2.5.2 on safety assessment of core spray sparger states: "The loss of the ability to distribute coolant to individual fuel bundles only has safety significance when the core cannot be fully flooded, as in the case of a recirculation line break...However, this loss of localized cooling would affect a limited number of bundles. The resultant consequences for BWR/3-6 plants would be bounded by plant safety analyses...In BWR/3 and BWR/4 plants (PBAPS is a BWR/4 plant), analysis has shown that steaming of water in the lower bundle provides adequate localized cooling...Therefore, in these plants, the loss of spray distribution has no safety significance". However, based on the latest position of GE on the core spray issue, as discussed in GE Position Summary DRF-E22-00135-01, Rev. 0, "Long-Term Post-LOCA Adequate Core Cooling Requirements," the applicant has acknowledged that spray is an intended function of the core spray spargers.

The applicant further stated that PBAPS Units 2 and 3 are following the latest BWRVIP Guidelines (ref. BWRVIP response to NRC safety evaluation of BWRVIP-18, dated

January 11, 1999). This latest guidance concedes that all plants are considered "geometry critical" with respect to core spray sparger examination. The Reactor Pressure Vessel and Internals ISI program, LRA Appendix B.2.7, directs reexamination of the sparger welds in accordance with the latest BWRVIP-18 guidelines.

b) The applicant asserts that because core spray piping is made of stainless steel material, corrosion is not a credible aging mechanism to cause flow blockage. Also, BWRVIP-18, "Core Spray Internals Inspection and Flaw Evaluation Guidelines," provides a means to inspect the core spray piping. The applicant stated that when performing the inspection of the welds and brackets for the aging effect of cracking, the nozzle openings are also visually inspected for flow blockage.

The applicant's examination of core spray spargers will detect missing or degraded spray nozzles, and it will take corrective actions if necessary, so that the original core spray distribution will be preserved during the extended period of operation. The staff finds the applicant's response acceptable because the intended function of the spargers is within the scope of license renewal, the spargers themselves are subject to aging management, and the applicant is following the latest BWRVIP guidelines for the inspection and re-inspection of the core spray piping and spargers. The BWRVIP AMP (aging management program) is evaluated in SER Section 3.0.3.9 "Reactor Pressure Vessel and Internals Inservice Inspection (ISI) program."

In RAI 2.3.1-2, the staff requested the applicant to verify whether the plant is equipped with a thermal shield, whose intended function is to provide shielding for the safety-related SSCs, such as the reactor vessel and the internals, from gammas and neutrons, and whether the shield may be relied on to minimize irradiation-induced embrittlement of the vessel and/or the internals. If the component exists at Peach Bottom, the staff requested the applicant to justify its exclusion from aging management; otherwise, submit an AMR for the subject component. The applicant's response stated that the BWR internals do not provide gamma or neutron shielding. This function is accomplished by the water. Further, the BWR design does not employ a thermal shield. Therefore, there is no need to identify such a component in the LRA. The staff finds the applicant's response assessment acceptable because the applicant stated that a thermal shield is not part of the Peach Bottom design.

The staff SER for BWRVIP-41 listed the jet pump sub-components that should be subject to an AMR. The following sub-components of the jet pump were listed in the BWRVIP-41 SER, and were also described in the Peach Bottom UFSAR section, "Jet Pump Assemblies"; but were not identified in the LRA: nozzle thermal sleeve, riser pipe, and diffuser. In RAI 2.3.1-4, the staff requested the applicant to explain why they were not within the scope of Part 54. In response, the applicant stated that the sub-components of the jet pump assembly were not separately identified in the LRA. The applicant further asserted that 10 CFR Part 54 only requires that the application include a list of components, and that the sub-components are not required to be listed. However, the applicant confirmed that the following sub-components are part of jet pump assembly, and that these sub-components will be subjected to aging management: riser pipe, riser elbows, thermal sleeve, diffusers, hold-down beams, riser braces, inlet-mixer nozzles, elbows and adapters, restrainer brackets and restrainer bracket wedges and adjusting screws. The staff finds the applicant's response acceptable.

On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.3.1.1.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the reactor pressure vessel and internals SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.1.2 Fuel Assemblies

2.3.1.2.1 Summary of Technical Information in the Application

The fuel assemblies are high-integrity 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 nuclear fuel is designed to assure that fuel damage limits will not be exceeded during either normal operation or anticipated operational occurrences. The nuclear fuel is utilized as the initial barrier for containment of fission products.

There are 764 fuel assemblies in each reactor, with each assembly consisting of a matrix of Zircaloy fuel rods.

Intended functions within the scope of license renewal:

Containment - The fuel cladding is the primary fission product barrier.

Table 2.3.1-2 of the LRA identified no component groups requiring aging management review, and noted that fuel assemblies do not require aging management review because they are short-lived.

2.3.1.2.2 Staff Evaluation

The staff reviewed Section 2.3.1.2 of the LRA and relevant sections of the Peach Bottom UFSAR to determine whether there is reasonable assurance that the fuel assembly system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule.

On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.3.1.2.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the fuel assemblies SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.1.3 Reactor Pressure Vessel Instrumentation System

2.3.1.3.1 Summary of Technical Information in the Application

The reactor pressure vessel instrumentation monitors and transmits information concerning key reactor vessel operating parameters during planned operations to ensure that sufficient control of these parameters is possible in order to avoid (1) release of radioactive material such that the limits of 10 CFR Part 20 are exceeded, (2) nuclear system stress in excess of that allowed by applicable industry codes, and (3) the existence of any operating conditions not considered by plant safety analyses.

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 various normal, transient, shutdown, and accident conditions.

Reactor vessel instrumentation is designed to provide the operator with sufficient indication of the following:

- Reactor core flow rate during planned operations to avoid operating conditions not considered by plant safety analyses.

- Reactor vessel water level during planned operations to determine that the core is adequately covered by the coolant inventory inside the reactor vessel to avoid the release of radioactive materials such that the limits of 10 CFR Part 20 are exceeded, and to avoid operating conditions not considered by plant safety analyses.

- Reactor vessel pressure and temperature during planned operations to avoid operating conditions not considered by plant safety analyses.

- Reactor vessel flange leakage during planned operations to avoid nuclear system stress in excess of that allowed by applicable industry codes and the release of radioactive material such that the limits of 10 CFR Part 20 are exceeded.

Intended functions within the scope of license renewal:

Provide signal input - The reactor pressure vessel instrumentation provides trip signals to plant safety systems, signals to plant non-safety systems, and plant process information.

Monitor key parameters - The reactor pressure vessel instrumentation monitors key water level, pressure, and temperature indications.

Table 2.3.1-3 of the LRA identified the component groups requiring aging management review. The component groups which were identified for the reactor pressure vessel instrumentations include: valve bodies, pipes, tubes, condensing chambers, and restricting orifices.

2.3.1.3.2 Staff Evaluation

The staff reviewed Section 2.3.1.3 of the LRA and relevant sections of the Peach Bottom UFSAR to determine whether there is reasonable assurance that the reactor pressure vessel instrumentation system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule.

On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.3.1.3.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the reactor pressure vessel instrumentation SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.1.4 Reactor Recirculation System

2.3.1.4.1 Summary of Technical Information in the Application

The reactor recirculation system is a reactivity control system that serves to control reactor power levels by varying the coolant rate through the core over a limited range so that greater versatility is available in making power adjustments without the use of control rods.

The recirculation system consists of two independent loops, external to the reactor pressure vessel, each with a motor-driven centrifugal pump, suction and discharge valves, piping, piping supports, and restraints. The recirculation system is part of the reactor coolant pressure boundary, and functions to maintain the pressure boundary during normal operation, transients, and accident scenarios to prevent the release of radioactive liquid and gas. The system piping and pump design pressures are based on the peak steam pressure in the reactor dome plus the static head above the lowest point in the recirculation loop.

The reactor recirculation system provides flow paths out of the reactor pressure vessel for residual heat removal (RHR) and reactor water cleanup systems and into the reactor vessel for RHR shutdown cooling and low pressure coolant injection.

The coolant flow rate through the reactor core is varied by using variable frequency motor-generator sets and flow control instrumentation to change the speed of the centrifugal pumps to control the recirculation system drive flow rate.

A recirculation pump trip on reactor high-pressure or reactor low water level has been provided to limit the consequences of a failure to scram during a transient.

Intended functions within the scope of license renewal:

Pressure boundary - The reactor recirculation system maintains the integrity of the reactor coolant pressure boundary.

RHR flow path - The reactor recirculation system provides flow paths for RHR shutdown cooling and low pressure coolant injection.

Flow-biased neutron monitoring - The reactor recirculation system supports average power range neutron monitor signal input.

Recirculation pump trip - The reactor recirculation pump motor-generator set supports anticipated transient without scram mitigation by recirculation pump trip.

Table 2.3.1-4 of the LRA identified the component groups requiring aging management review. The component groups which were identified for the reactor recirculation system include: valve bodies, pump casings, pipes, tubing, flow elements, thermowells, and restricting orifices.

2.3.1.4.2 Staff Evaluation

The staff reviewed Section 2.3.1.4 of the LRA and relevant portions of the UFSAR for Peach Bottom to determine whether there is reasonable assurance that the reactor recirculation system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

After completing the initial review, the staff requested the applicant to provide additional information on the reactor recirculation system. The applicant's response to the requests for additional information (RAIs) are discussed below.

In RAI 2.3.1-3, the staff requested the applicant to verify whether the pumps at Peach Bottom, such as the recirculation pumps, are designed with lube motor-oil collection systems, as required under 10 CFR Part 50, Appendix R, III O. If they are, then the components should be in-scope requiring aging management. It appeared that the subject components were not identified in the LRA, and therefore, it was requested that the exclusion be justified.

In response, the applicant stated that 10 CFR Part 50 Appendix R, III O, requires oil collection systems for reactor coolant pumps if the containment is not inerted during normal operation. It was further stated that the PBAPS containments are inerted during normal operation, and therefore, this requirement is not applicable. The staff finds the applicant's assessment acceptable.

On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.3.1.4.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the reactor recirculation SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.2 Engineered Safety Features Systems

In Section 2.3.2, "Engineered Safety Features Systems (ESF)," of the Peach Bottom Atomic Power Station, Units 2 & 3, License Renewal Application (the LRA), Exelon (the applicant) described the systems, structures and components (SSCs) of the ESF that are subject to aging management review (AMR) for license renewal.

2.3.2.1 High-pressure Coolant Injection System

2.3.2.1.1 Summary of Technical Information in the Application

As described in the LRA, the high-pressure coolant injection (HPCI) system is provided to assure that the reactor is adequately cooled to limit fuel clad temperature in the event of a small break in the nuclear system and loss of coolant which does not result in rapid depressurization of the reactor vessel. The system is designed to allow the plant to be shut down while maintaining sufficient reactor vessel water inventory until the reactor vessel is depressurized. The HPCI system continues to operate until reactor vessel pressure is below the pressure at which low pressure coolant injection (LPCI) operation or core spray system operation maintains core cooling.

The HPCI system consists of a turbine driven pump, piping, valves, and controls which provide for a complete and independent emergency core cooling system. The primary water source is water from the condensate storage tank, with a backup supply of water available from the suppression pool. Delivery of water to the vessel occurs via the "A" feedwater line. Steam supply to the HPCI turbine is from the reactor via the "B" main steam line. The system is equipped with a test line shared with the reactor core isolation cooling system to permit functional testing and a minimum flow bypass line which directs flow to the suppression pool for pump protection purposes during periods of low system flow. The exhaust steam from the turbine is discharged to the suppression pool.

Intended functions within the scope of license renewal:

Coolant injection - The HPCI system provides sufficient coolant to the reactor vessel to limit fuel clad temperature in the event of a small break in the reactor coolant system and a subsequent loss of coolant which does not result in a rapid depressurization of the reactor vessel.

Table 2.3.2-1 of the LRA identified the component groups requiring aging management review. The component groups which were identified for the HPCI include: valve bodies, pump casings, filter bodies, turbine casings, flexible hoses, gland seal condenser, turbine lube oil cooler, pump room cooling coils, piping, tubing, fittings, thermowell, flow elements, restricting orifice, steam trap, rupture disc, sparger, suction strainers, and lubricating oil tanks.

2.3.2.1.2 Staff Evaluation

The staff reviewed Section 2.3.2.1 of the LRA and relevant sections of the Peach Bottom UFSAR to determine whether there is reasonable assurance that the high-pressure coolant injection system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

In response to a staff RAI, the applicant stated in the letter dated May 22, 2002 that as result of the applicants system boundary realignment, the HPCI pump room cooling coils are realigned from the Reactor Building Ventilation System to the HPCI system for license renewal, and are addressed in LRA Table 2.3.2-1. The staff noted that pressure boundary is the only intended function identified in LRA Table 2.3.2-1 for the HPCI pump room cooling coils. In a telephone conference call on August 5, 2002, the applicant further clarified that the instrumentation in the HPCI room which needed to be protected against extreme environmental conditions was relocated outside the room. As a result, the applicant’s EQ analysis for the HPCI pump room for the environmental conditions that were postulated to occur during postulated design basis accidents for the plants determined that the HPCI pump room cooling coils are not required to maintain the operability of the HPCI system during these events. Additional discussion on the applicant’s boundary realignment is provided in Section 2.2.3 of this SER. The staff found the applicant’s response acceptable.

On the basis of the above review, the staff did not find any omissions by the applicant of SCCs within the scope of license renewal.

2.3.2.1.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified HPCI SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR Part 54.4 and 10 CFR Part 54.21(a)(1).

2.3.2.2 Core Spray System

2.3.2.2.1 Summary of Technical Information in the Application

The core spray system (CS) provides a redundant means for removal of decay heat from the core following a postulated LOCA. The system also provides a means for flooding the reactor vessel to remove decay heat from the core to support alternate shutdown cooling.

The system consists of two independent loops per unit, each with two 50% capacity motor driven pumps and associated piping, valves, and instrumentation necessary to perform the system intended functions. The core spray system automatically sprays water onto the top of the fuel assemblies upon receipt of signals indicative of a LOCA. The system delivers cooling water at a sufficient flow rate to cool the core and prevent excessive fuel clad temperature. The low pressure coolant injection system initiates on the same signal as the core spray system and operates independently to fulfill the same objective as the core spray system. The system is maintained in a standby condition, powered by independent safeguard buses in the electrical distribution system.

The core spray system provides protection to the core for large break scenarios with resultant low reactor pressure. In addition, protection can be afforded for small-break scenarios in which the automatic depressurization system has initiated to lower reactor vessel pressure.

Intended functions within the scope of license renewal:

Core cooling - The core spray system provides water to spray onto the top of the fuel assemblies to cool the core and prevent excessive fuel clad temperature following a design basis accident.

Minimum flow bypass - The core spray system has a minimum flow bypass mode which is initiated for pump protection whenever a core spray pump is operating and flow through the pump is low.

Table 2.3.2-2 of the LRA identified the component groups requiring aging management review. The component groups which were identified for the CS include valve bodies, pump casings, pump motor oil cooler, pump room cooling coils, piping, tubing, restricting orifices, flow elements, thermowells, cyclone separators, and suction strainers.

2.3.2.2.2 Staff Evaluation

The staff reviewed Section 2.3.2.2 of the LRA and relevant sections of the Peach Bottom UFSAR to determine whether there is reasonable assurance that the core spray system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

As discussed in Section 2.3.1.1.2 of this SER, the staff identified that the applicant did not include the spray function of the core spray spargers as a license renewal intended function. However, the applicant subsequently agreed to include the core spray function of the spargers within the scope of license renewal and maintain the core spray distribution as originally designed during the extended period of operation.

Based on the discussion on system boundary realignment in Section 2.2.3 of this document, the core spray pump room cooling function was realigned to the CS system. However, the staff notes that Table 2.3.2-2, as presented in the LRA, identifies heat transfer as an intended function for the core spray pump room cooling coils. Therefore, the boundary realignment did not impact the staff's conclusion in this section.

On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.3.2.2.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the core spray SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.2.3 Primary Containment Isolation System

2.3.2.3.1 Summary of Technical Information in the Application

The primary containment isolation system (PCIS) is a plant protection system and includes the steam leak detection system. The system provides timely protection against the onset and consequences of accidents involving the gross release of radioactive materials from the fuel and nuclear system process barrier. The primary containment and reactor vessel isolation control system initiates automatic isolation of appropriate lines that penetrate the primary containment whenever monitored variables exceed preselected operational limits.

The system initiates isolation of the reactor pressure vessel, isolation of piping which penetrates primary containment, and isolation of piping in selected balance of plant systems that provide potential paths for the release of radioactive materials coming from breaks in the reactor coolant pressure boundary.

Intended functions within the scope of license renewal:

Reactor pressure vessel isolation - The primary containment isolation system initiates isolation of the reactor pressure vessel to contain released fission products in the event of gross fuel failure.

Primary containment isolation - The primary containment isolation system initiates automatic closure of isolation valves in piping that penetrates the primary containment whenever monitored parameters indicate a fluid loss from the reactor coolant pressure boundary or high leakage from the piping for selected nuclear steam supply or auxiliary systems.

Leak detection - The steam leak detection system provides piping and equipment area high-temperature signals when steam leaks from high-energy piping cause unacceptably high temperatures.

Table 2.3.2-3 of the LRA identified the component groups requiring aging management review. The component groups which were identified for the PCIS include valve bodies, piping, tubing, restricting orifices, and flow elements.

2.3.2.3.2 Staff Evaluation

The staff reviewed Section 2.3.2.3 of the LRA and relevant sections of the Peach Bottom UFSAR to determine whether there is reasonable assurance that the primary containment isolation system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

After completing the initial review, the staff requested the applicant to provide additional information on the PCIS. By the letter dated May 6, 2002, the applicant responded to the staff's request for additional information (RAI) as discussed below.

One of the intended functions of the main steam line flow restrictors is to limit steam line flow during a steam line rupture outside of primary containment until the MSIVs can close, thereby limiting potential radioactive release. Over the extended life of the plant, it is therefore essential to maintain the flow area of the flow restrictors used in the CLB to calculate the amount of steam released. The staff believes that erosion/corrosion due to high-energy steam flow can eventually increase this flow area beyond the value used in the CLB. It appears from Table 3.4-1 of the LRA that the applicant's aging management program for flow-accelerated corrosion (FAC), which was implemented as required by NRC Generic Letter 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning", has not been applied to the flow restrictor component groups; however, for some of the flow restrictors, the Inservice inspection (ISI) program is applied in addition to RCS chemistry control. In RAI 2.3.2-1, the staff requested the applicant to provide the following information:

a) Are the main steam line flow restrictors, and their flow restriction function within-scope? If not, why?

b) If in-scope, how will the applicant determine that the flow area does not exceed the value used in the CLB, so that the intended functions will be maintained consistent with the CLB for the period of extended operation?

In response, the applicant clarified that the main steam line flow restrictors are in the scope of license renewal. The main steam line flow restrictors are identified under Piping Specialties in LRA Table 3.4.1. The main steam line flow restrictor is identified in the LRA as a flow element consisting of a body and a throat. The intended function of the flow element throat is identified as throttle, which addresses the main steam line flow restriction function. The main steam line flow restrictors are designed with a throat constructed of stainless steel. The applicant further stated that in accordance with EPRI NSAC-202L-R2, “Recommendations for an Effective Flow-Accelerated Corrosion Program,” stainless steel components are not susceptible to flow-accelerated corrosion. The LRA identifies aging effects of loss of material and cracking for the stainless steel throat. The aging management program identified in the LRA is discussed in Section 3.4.2 on this SER. The staff finds the applicant’s assessment acceptable.

As a result of the applicant’s system boundary realignment, Table 2.3.2-3 of the LRA includes valve bodies and pipes from 12 non-safety-related systems within-scope, which perform primary containment isolation function. In response to the staff RAI of March 12, 2002, the applicant provided a supplement to Table 2.3.2-3 which added the component groups of valve bodies and pipes from the torus water cleanup system. These components perform the intended function of pressure boundary. The staff finds the addition of the component groups acceptable because they perform the intended function of pressure boundary, and are passive and long-lived. This modification was documented in the applicant’s letter dated May 22, 2002. Additional discussions on the applicant’s boundary realignment are provided in Section 2.2.3 of this document.

On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.3.2.3.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the primary containment isolation SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.2.4 Reactor Core Isolation Cooling System

2.3.2.4.1 Summary of Technical Information in the Application

The reactor core isolation cooling (RCIC) system is a high-pressure coolant makeup system which supports safe shutdown of the reactor whenever the reactor is isolated from its heat sink at elevated temperatures and pressures. The system functions to prevent a release to the environs because of inadequate core cooling. The RCIC system has sufficient makeup capacity to accommodate decay heat boiloff during a normal shutdown when the reactor is isolated from its normal heat sink at elevated pressure. The system will facilitate depressurization of the reactor vessel until the shutdown cooling mode of the residual heat removal (RHR) system can be placed in operation. The primary water source is demineralized water from the condensate storage tank, with a backup supply of treated water available from the suppression pool.

The RCIC system consists of a turbine driven pump, piping, valves, and controls, which provide for delivery of makeup water to the reactor vessel. The system is equipped with a test line shared with the high-pressure coolant injection system to permit functional testing and a minimum flow bypass line which directs flow to the suppression pool for pump protection purposes during periods of low system flow. The exhaust steam from the turbine is directed to the suppression pool.

Intended functions within the scope of license renewal:

Coolant injection - The RCIC system provides makeup water to the reactor vessel during shutdown and reactor isolation in order to prevent excessive fuel cladding temperatures.

Reactor vessel level control - The RCIC system provides reactor vessel level control to maintain water level in the reactor vessel above the top of the active fuel should the reactor vessel be isolated from normal feedwater flow.

Reactor vessel pressure control - The RCIC system provides reactor pressure control by drawing off steam for turbine operation and directing the discharge to the suppression pool. The pressure will decay to the level suitable for operation of the shutdown cooling mode of the RHR system.

Table 2.3.2-4 of the LRA identified the component groups requiring aging management review. The component groups which were identified for the RCIC include valve bodies, pump casings, strainer bodies, turbine casings, turbine lube oil cooler, pump room cooling coils, piping, tubing, fittings, flow element, thermowells, Y-strainer bodies, Y-strainer screens, restricting orifices, steam traps, rupture discs, suction strainers, tank.

2.3.2.4.2 Staff Evaluation

The staff reviewed Section 2.3.2.4 of the LRA and relevant sections of the Peach Bottom UFSAR to determine whether there is reasonable assurance that the reactor core isolation cooling system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

In response to a staff RAI, the applicant stated in the letter dated May 22, 2002 that as a result of the applicant's system boundary realignment, the RCIC pump room cooling coils are realigned from the Reactor Building Ventilation System to the RCIC system for license renewal, and are addressed in LRA Table 2.3.2-4. The staff noted that pressure boundary is the only intended function identified in LRA Table 2.3.2-4 of the RCIC pump room cooling coils. In a telephone conference call on August 5, 2002, the applicant further clarified that the instrumentation in the RCIC room which needed to be protected against extreme environmental conditions was relocated outside the room. As a result, the applicant's EQ analysis for the RCIC pump room for the environmental conditions that were postulated to occur during postulated design basis accidents for the plants determined that the RCIC pump room cooling coils are not required to maintain the operability of the RCIC system during these events. Additional discussion on the applicant's boundary realignment are provided in Section 2.2.3 of this SER. The staff found the applicant's response acceptable.

On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.3.2.4.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the RCIC SSCs that are within the scope of license renewal and are subject to an AMR in accordance with 10 CFR Part 54.4 and 10 CFR Part 54.21(a)(1).

2.3.2.5 Residual Heat Removal System

2.3.2.5.1 Summary of Technical Information in the Application

The residual heat removal (RHR) system is an emergency core cooling system and heat removal system. The RHR system restores and maintains the coolant inventory in the reactor vessel such that the core is adequately cooled after a LOCA. The system also provides containment cooling by condensing steam resulting from the blowdown due to a design basis accident.

The RHR system consists of two independent loops. Each loop consists of two heat exchangers, two parallel RHR pumps, plus the associated piping, valves, and instrumentation. The loops are located in different areas of the reactor building to minimize the possibility of a single physical event causing the loss of the entire system.

The RHR system is designed for three modes of operation: shutdown cooling, containment cooling, and low-pressure injection. Each mode of operation is defined as a subsystem of the RHR system, with each subsystem contributing toward satisfaction of all objectives and design bases of the system.

The shutdown cooling subsystem is placed in operation during a normal shutdown and cooldown. The subsystem uses one or more RHR heat exchangers to remove reactor core decay heat and sensible heat from the reactor core to achieve and maintain the reactor in a cold shutdown condition.

The containment cooling subsystem provides a means for cooling the containment when operating in either the suppression pool cooling or the containment spray modes. The suppression pool cooling mode provides a means to remove the reactor core decay heat and sensible heat discharged to the suppression pool in the event of a design basis accident or event. The containment cooling subsystem also provides the ability to reduce containment pressure by using the spray headers in the drywell and above the suppression pool.

The low pressure coolant injection (LPCI) subsystem operates to restore and, if necessary, maintain the coolant inventory in the reactor vessel after a LOCA so that the core is sufficiently cooled to preclude excessive fuel clad temperature. The LPCI subsystem operates in conjunction with the high-pressure coolant injection system, the automatic depressurization system, and the core spray system to achieve this goal. The LPCI subsystem is designed to reflood the reactor vessel to at least two-thirds core height and maintain this level. After the core has been flooded to this height, the capacity of one RHR pump is more than sufficient to maintain the level.

Intended functions within the scope of license renewal:

Shutdown cooling - the RHR system provides the shutdown cooling function to remove decay heat and sensible heat from the primary system following depressurization of the reactor.

Containment cooling - The RHR system provides a means to cool the containment when operating in the suppression pool cooling or containment spray mode.

Alternate shutdown cooling - The RHR system provides alternate heat removal capability to cool the core in the event that the shutdown cooling mode of the system cannot be established.

Low pressure coolant injection (LPCI) - The LPCI subsystem operates to restore and maintain the coolant inventory in the vessel post-LOCA so that the core is sufficiently cooled to preclude excessive fuel clad temperatures.

Minimum flow bypass - The RHR system has a minimum flow bypass mode which is initiated for pump protection whenever an RHR pump is operating and flow through the pump is low.

Sample isolation - The RHR sample valves isolate on a primary containment isolation system Group I signal.

Table 2.3.2-5 of the LRA identified the component groups requiring aging management review. The component groups which were identified for the RHR include: Valve bodies, pump casings, heat exchangers, pump room cooling coils, piping, tubing, thermowells, flow elements, cyclone separators, restricting orifices, and suction strainers.

2.3.2.5.2 Staff Evaluation

The staff reviewed Section 2.3.2.5 of the LRA and relevant sections of the Peach Bottom UFSAR to determine whether there is reasonable assurance that the residual heat removal system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

After completing the initial review, the staff requested the applicant to provide additional information on the RHR. By the letter dated May 6, 2002, the applicant responded to staff's request for additional information (RAI) as discussed below.

The LPCI coupling was identified in the BWRVIP-06 report as a safety-related component. It appears, however, that the component was not identified in the LRA as requiring an AMR. In RAI 2.3.2-2, the staff requested that if the component exists at Peach Bottom, then the applicant should justify its exclusion from aging management; otherwise, submit an AMR for the subject component. In response dated May 6, 2002, the applicant stated that neither PBAPS unit has a LPCI coupling, and therefore it was not identified in the LRA. The staff consider the RAI response was acceptable because the LPCI coupling was not part of the plant's design.

The containment spray mode of RHR utilizes ring headers located in the drywell and suppression chamber. The applicant indicated that it considered the spray nozzles as part of the containment spray ring header piping. However, in response to a staff RAI, which is further discussed in Section 2.2.3 of this document, the applicant agreed to identify the spray nozzles as individual components rather than grouped under the category of containment spray ring header piping. The LRA Table 2.3.2-5 was revised accordingly.

Based on the discussion on system boundary realignment in Section 2.2.3 of this document, the RHR pump room cooling function was realigned to the RHR system. The staff notes that Table 2.3.2-5, as presented in the LRA, identifies heat transfer as an intended function for the RHR pump room cooling coils, in addition to the pressure boundary function. This is acceptable to the staff.

On the basis of the above review the staff did not find any omissions by the applicant of SSC's within the scope of license renewal.

2.3.2.5.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the residual heat removal SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.2.6 Containment Atmosphere Control and Dilution System

2.3.2.6.1 Summary of Technical Information in the Application

In Section 2.3.2.6 of the LRA, the applicant identified the components of the containment atmosphere control (CAC) and containment atmospheric dilution (CAD) systems that are subject to an AMR and described their intended functions. Additional information concerning the CAC and CAD systems is provided in Section 5.2 of the UFSAR for both Units 2 and 3. The components of these systems that fall within the scope of license renewal are shown in CAC license renewal drawing LR-M-367, sheets 1-3, all Rev. A, and in CAD license renewal drawing LR-M-372, sheets 1-4, all Rev. A.

The CAC and CAD systems are designed to supply and maintain an inert atmosphere inside primary containment for combustible gas control. The CAC system is designed to purge air from the primary containment atmosphere (drywell and torus) with nitrogen until the containment atmosphere contains less than 4 percent oxygen by volume during startup and provides a supply of makeup nitrogen during normal operation.

The containment atmospheric dilution (CAD) system is a standby system during normal operation of the plant. Following a design basis LOCA, the primary means of hydrogen control at Peach Bottom is maintaining the normally inerted containment atmosphere and controlling the intrusion of oxygen into the containment. No credit is assumed for operation of the CAD system in the UFSAR Chapter 14 accident analysis. However, the CAD system is maintained to meet the requirements of GDCs 41, 42, and 43 of Appendix A to 10 CFR Part 50 and

10 CFR 50.44. Following a beyond design basis LOCA, the CAD system is used instead of the normal nitrogen inerting system to maintain the oxygen concentration within the containment at less than 5 percent by volume.

Included among the major equipment for the CAC system are a liquid nitrogen storage tank, a water-bath vaporizer, ambient vaporizers, an electric heater, valves, piping, controls and instrumentation. Major components of the CAD system are a liquid nitrogen storage tank, electrical vaporizers, valves, piping, controls and instrumentation. The containment atmosphere is monitored by a combined CAD and CAC analyzer system. The CAD and CAC analyzer system consists of two redundant combustible gas (H2 and O2) detection chambers.

The applicant determined that the following intended functions for the CAC and CAD systems fall within the scope of license renewal.

- Containment pressure control - The CAD system provides a means for controlling containment pressure following a design basis event.

- Nitrogen source - The CAD liquid nitrogen storage tank is the source of nitrogen for the safety grade instrument gas system.

- Combustible gas monitoring - The CAD and CAC analyzer system monitors the oxygen and hydrogen concentration in the containment atmosphere.

On the basis of the intended functions of the CAD and CAC systems that are identified above and the methodology described in Section 2.1.2 of the LRA, the applicant compiled a list of component groups within the scope of license renewal and subject to an AMR. The applicant also identified the intended functions and environments for each component group. The applicant supplied this list in Table 2.3.2-6 of the LRA, which identifies four types of component groups with six types of components:

- casting and forgings (valve bodies, pump casings)
- piping (pipe)
- piping specialities (nitrogen electric vaporizer)
- vessels (nitrogen storage tanks, H2 and O2 detection chambers).

In LRA Table 2.3.2-6, the applicant identified pressure boundary as the intended function associated with components of the CAD and CAC systems that are subject to an AMR.

2.3.2.6.2 Staff Evaluation

The staff reviewed Section 2.3.2.6 of the LRA, UFSAR Section 5.2, and related UFSAR sections describing the CAC and CAD systems and systems that support the function of the CAC and CAD systems to determine whether there is reasonable assurance that the containment atmosphere control and dilution system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

The staff review could not determine whether certain CAC and CAD components that are shown on drawing LR-M-372 as being within the scope of license renewal were included in the list of components subject to an AMR identified in Table 2.3.2-6 of the LRA. Therefore, the staff issued RAI 2.3.2.6-1 to determine whether the applicant considered the following components and housings within the scope of license renewal and subject to an AMR:

- atmospheric vaporizer 60GC-1, sheet 1, location G4
- pressure build coil, sheet 1, location G4
- numerous fittings, increasers, and reducers
- rupture disk, sheet 1, location G4
- numerous flow elements
- numerous temperature elements

By letter dated May 22, 2002, the applicant responded that the atmospheric vaporizer and the pressure build coils are categorized as pipe and are therefore included in the piping component group in LRA Table 2.3.2-6. The applicant stated that the reducers and increasers are fittings which it considered part of the piping system. As described in Section 3.0 of the LRA, the component group of piping includes piping, tubing, and fittings. Thus, increasers and reducers are included in the piping component group in LRA Table 2.3.2-6. The identified rupture disk, flow elements, and thermowells (pressure boundary components associated with temperature elements) also fall within the scope of license renewal and are subject to an AMR. These components were inadvertently omitted from LRA Table 2.3.2-6 and also LRA Table 3.2-6. In response to RAI 2.3.2.6-1, the applicant resubmitted LRA Tables 2.3.2-6 and 3.2-6, after revising them to include the omitted components. The staff considers the applicant's response to RAI 2.3.2.6-1 to be acceptable because it indicates that, in accordance with 10 CFR 54.21(a)(1), the passive, long-lived components in question will be subject to an AMR.

During its review, the staff determined that containment inerting was not identified as a CAC and CAD system intended function in the LRA along with the above-listed functions of controlling primary containment pressure, providing a nitrogen source for safety-grade instrument gas, and monitoring the concentration of combustible gas inside primary containment. The CAD purge mode is required to meet the technical specification requirement that the primary containment be purged of air with nitrogen until the atmosphere contains less than 4 percent oxygen. The UFSAR Section 5.2.3.8 further reads: "Reference 12 [of the UFSAR], states that although the [CAD] system is no longer assumed to be the primary means of combustible gas control, the system will be maintained as originally installed." In light of the UFSAR's statement that the CAD system is to be maintained as installed, the staff was concerned that the LRA did not provide reasonable assurance that it is acceptable to exclude the CAD system's primary containment inerting function from being classified as an intended function. Therefore, on March 12, 2002, the staff issued RAI 2.3.2.6-2 to request that the applicant provide the basis for excluding the primary containment inerting intended function of the CAD purge mode from the scope of license renewal.

In a letter dated May 22, 2002, the applicant responded that the primary containment inerting function does not meet the 10 CFR 50.49(b)(1) definition of safety-related and therefore is not considered a safety-related intended function for license renewal. The primary containment atmosphere is maintained at less than 4 volume percent oxygen concentration in accordance with the technical specifications, so that in the event of a LOCA, the postulated resulting hydrogen and oxygen generation will not result in a combustible mixture inside containment. In addition, Peach Bottom UFSAR Section 5.2.3.8, Subsection 5.2.3.8.1, page 5.2-15b, Rev. 17 04/00, states that the purpose of the inerting system is to assure that the initial concentration of O^2 prior to a LOCA is maintained below the flammable limits within primary containment. Following a design basis accident, the UFSAR indicates that the primary method of combustible gas control is through maintaining the primary containment atmosphere in its initially nitrogen-inerted state and ensuring that no external sources of oxygen are introduced into containment. Therefore, the inerting function is used to establish and maintain technical-specification-required containment atmosphere conditions but is not required to mitigate postulated accidents.

The applicant further responded that the operation of the CAD system and its potential contribution to offsite dose is not assumed in the plant accident analysis described in UFSAR Chapter 14. As described in UFSAR Section 5.2.3.9.2, the CAD system is designed to comply with the requirements of 10 CFR 50.44. Although the system is no longer assumed to be the primary means of combustible gas control, the system will be maintained as originally installed. This statement requires that the CAD system be maintained as originally designed, but eliminates the need to reevaluate the system's design for design changes that have no impact on the original CAD system design basis. On the basis of the above CLB description, the applicant stated that the primary containment inerting function is not a safety-related intended function for license renewal.

With respect to the applicant's response to RAI 2.3.2.6-2, the staff concurs that the containment inerting function is not an intended function for license renewal. The plant technical specifications do not permit extended power operation with the containment in a noninerted condition, and the inerting function of the CAC and CAD system is not required to mitigate design basis accidents. Therefore, in accordance with 10 CFR 54.4, the applicant's response is acceptable.

In RAI 2.3.2.6-3, the staff inquired as to whether the applicant identified all of the intended functions of H^2 and O^2 detection chambers. LRA Table 2.3.2-6 listed pressure boundary as the only intended function of these components, though they also appeared to perform an intended function of combustible gas monitoring for the CAC and CAD system. In a letter dated May 22, 2002, the applicant responded that the combustible gas monitoring function identified in LRA Section 2.3.2.6 is a system intended function and not a component intended function, and therefore is not included in Table 2.3.2-6.

The staff considers the applicant's differentiation between system functions and component functions not pertinent to the reason the rule requires intended functions to be specified. Section 54.21(a)(3) of 10 CFR Part 54 states that during the IPA process, applicants must identify and list the intended function of each structure and component meeting the scoping criteria of 10 CFR Part 54.4 to "demonstrate that the effects of aging will be adequately managed so that the intended function will be maintained consistent with the CLB for the period of extended operation." That is, the intended functions guide the selection of an appropriate set of aging management programs for the component in question.

However, based upon the discussion in UFSAR Section 5.2.3.9.4, the staff concludes that the H^2 and O^2 detection chambers are mechanical components which form a pressure boundary to allow the primary containment atmosphere to be monitored through an active, electrochemical process. As the detection chambers merely form the requisite pressure boundary and do not otherwise contribute to the electrochemical process used to detect combustible gases, the staff agrees that the detection chambers do not serve a combustible gas monitoring function. Therefore, the staff has concluded that the applicant has adequately identified the intended functions of the H^2 and O^2 detection chambers in accordance with 10 CFR 54.4.

On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.3.2.6.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the containment atmosphere control and dilution SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.2.7 Standby Gas Treatment System

2.3.2.7.1 Summary of Technical Information in the Application

The standby gas treatment system (SGTS) is an engineered safety feature system for limiting the ground-level release from the reactor building that surrounds the primary containment and provides a secondary containment barrier during postulated design basis accidents (DBAs). The SGTS also provides for an elevated release point of primary and secondary containment air via the main exhaust stack. The SGTS system is common to both Peach Bottom Atomic Power Station (PBAPS) Units 2 and 3 and is located in a shielded room in the radwaste building between the reactor buildings.

In Section 2.3.2.7 of the LRA, the applicant identified the components of the SGTS that fall within the scope of license renewal and are subject to an AMR. The SGTS is described in Section 5.3.3 of the UFSAR for PBAPS Units 2 and 3. The system scoping is shown in license renewal boundary drawings LR-M-391, Rev. A, and LR-M-397, Rev. A, for both units.

The SGTS consists of two parallel air filtration trains connected to three full-capacity exhaust fans. Each filter train is sized to treat a rated flow of 10,500 cfm. Each fan is capable of exhausting the rated flow through either filter train. Each train consists of a moisture separator, electric resistance heater, pre-filter, high-efficiency particulate air (HEPA) filter, charcoal filter, and a final HEPA filter. The discharge lines from the trains tie together into an 18-in. diameter header for discharge into the main exhaust stack. Inlet flow to the two SGTS filter trains is from a common plenum connected to two exhaust lines from the reactor building ventilation system. One line is connected to the reactor building refueling floor exhaust duct. The second line is connected to the air spaces below the refueling floor and also to the torus and drywell.

Following the receipt of a reactor building isolation signal, the reactor building ventilation isolation valves rapidly isolate the reactor building atmosphere, preventing the escape of potentially contaminated air. At the same time, the SGTS is automatically started to maintain a negative pressure in the reactor building. With the reactor building isolated, each of the two exhaust fans has the necessary capacity to maintain the reactor building at a minimum negative pressure of 0.25-in. water gauge.

The initial scoping performed by the applicant determined that the following intended functions for the SGTS fall within the scope of license renewal:

- Filtration - Following a design basis accident, the SGTS filters the exhaust air to remove radioactive gases and particulates that may be present in the secondary containment prior to discharge to the environment.

- Containment - The SGTS maintains a negative pressure in the reactor building under normal atmospheric conditions.

- Elevated release - The SGTS provides for an elevated release of radioactive materials post-LOCA to minimize the release of radioactive materials to the environment during accident conditions.

On the basis of the intended functions identified above, the applicant determined that all SGTS safety-related components (electrical, mechanical, and instrument) fall within the scope of license renewal. The applicant described its process for identifying the mechanical components subject to an AMR in Section 2.1.2 of the LRA. Based on this methodology, the applicant compiled a list of the component groups that are within the scope of license renewal and are subject to an AMR. The applicant listed these component groups in Table 2.3.2-7 of the LRA. The applicant identified the following component groups as falling within the scope of license renewal and subject to an AMR:

- casting and forgings (valve bodies)
- elastomer (fan flex connections, filter plenum access door seals)
- piping (pipe, tubing, fittings)
- piping specialities (flow elements, pressure elements, temperature element couplings)
- sheet metal (ducting, plenums, fan enclosures, damper enclosures, louvers)

In Table 2.3.2-7, of the LRA the applicant further identified that the pressure boundary and throttle intended functions are the only intended functions associated with components of the SGTS that are subject to an AMR.

2.3.2.7.2 Staff Evaluation

The staff reviewed Section 2.3.2.7 of the LRA, Section 5.3.3 of the Peach Bottom UFSAR, and license renewal drawings LR-M-391, sheets 1 and 2, and LR-M-397, sheets 1-3, Rev. A, to determine whether there is reasonable assurance that the SGTS components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components

having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

In a letter dated March 12, 2002, after completing the initial review, the staff requested additional information concerning the exclusion of certain SGTS components from the scope of license renewal. The applicant submitted responses to those RAIs, as discussed below.

In RAI 2.3.2.7-1(a), the staff determined that the license renewal drawings for SGTS (LR-M-397, sheet 1) show additional components within the scope of license renewal that were not listed in LRA Table 2.3.2-7:

- demisters OAV347 (Train A) at location F7 and OBV347 (Train B) at location C7
- heating coils OAE065 (Train A) at location F7 and OBE065 (Train B) at location C7
- prefilters OAF034 (Train A) at location F6 and OBF034 (Train B) at location C6
- HEPA filters OAF035 (Train A) at location F6 and OBF035 (Train B) at location C6
- charcoal filters, OAF036 (Train A) at location F6, and OBF036 (Train B) at location C6
- HEPA filters OAF037 (Train A) at location F6 and OBF037 (Train B) at location C6
- fire spray nozzles shown at locations F6 (Train A) and C6 (Train B)

In addition, the RAI stated that if the filter media for the components listed above (prefilters, HEPA filters, charcoal filters) were excluded on the basis that these media components are routinely replaced (consumables), the applicant should describe the plant-specific monitoring program and the specific performance standards and criteria for periodic replacement. The components listed above typically are located in engineered safety-features (ESF) filtration housing.

In a letter dated May 22, 2002, applicant responded that the components identified above are included in the scope of license renewal but are not subject to an AMR as they are short-lived passive components. The filter media for these components (prefilters, HEPA filters, charcoal filters) are condition monitored at a frequency of once every 12 months using station procedures ST-M-09A-600-2 (3) and ST-M-09A-610-2 (3) and are replaced if filter failure is determined. A review of the plant history for these components indicated that some or all of these filters were replaced during the last 20 years and it is expected that they will be replaced again in the future. The ducting and plenum that house the above components are included in the scope of license renewal and are subject to an AMR. These are included in Table 2.3.2-7 and Table 3.2-7 of the LRA.

The staff considers the applicant's response is partially acceptable since prefilters, HEPA filters, and charcoal filters are governed by technical specification (TS) requirements or plant procedures which provide for their replacement in accordance with TS surveillance requirements or plant procedures. The staff does not agree that the demisters, fire spray nozzles, and heating coils should be excluded from AMR because if any one of these components should fail, the intended function of the filtration unit may not be accomplished. This was Open Item 2.3.2.7.2-1.

In a letter dated November 26, 2002, the applicant provided additional clarifying information stating that the demisters have been included in the AMR for the SGTS as part of Tables 2.3.2-7 and 3.2-7 of the LRA and fire spray nozzles are included in the scope of license renewal and subject to an AMR in the LRA Table 2.3.3-7 under fire protection system as piping specialties-discharge nozzles. The heating coils, which are electric heating coils, were evaluated and determined to be within the scope of license renewal. They are installed and enclosed within the SGTS filter plenum. The plenum is included in LRA Table 2.3.2-7 and subject to an AMR. These electric heating coils are active components and do not have a pressure boundary housing, and therefore, they are not subject to an AMR. In addition, the staff coinfirmed that the Peach Bottom, Units 2 and 3, technical specification, 3.6.4.3, "Ventilation Systems," Surveillance Requirements 3.6.4.3.2 verifies the performance of the electric coils of the filtration system.

On the basis of the additional information provided by the applicant regarding the demisters, fire spray nozzles and electric heating coils, the NRC staff agrees with the applicant's response for the demisters and fire spray nozzles since they are subject to an AMR as identified in Tables 3.2-7 and 3.3-7, respectively. The staff agrees that the electric heating coils are within the scope of license renewal but do not require an AMR because 10 CFR 54.21 specifies that only components that perform their function with moving part or by changing state are within the scope of license renewal; therefore, Open Item 2.3.2.7.2-1 is closed.

In RAI 2.3.2.7-1(b) the staff asked why LRA Table 2.3.2-7 did not identify the drywell purge supply and exhaust filtration system components and their housings shown on license renewal drawing LR-M-391, sheets 1 and 2, as falling within the scope of license renewal. Specifically, the staff asked applicant to justify the exclusion of the following components and housings:

- piping (or ductwork) and valve (or damper) housings for AO-20452 through AO-20470 at locations F7, E7, D7&D8, F3&F4, E2&E3, D3, C4, and B4
- piping (or ductwork) at locations between B6 through E6
- instrumentation taps at locations F3, F7, E2, E7, D3, D7 (two), and B6
- piping (or ductwork) and valve (or damper) housings for AO-30452 through AO-30470 at locations F7, E7, D7&D8, F3&F4, E2&E3, D3, C4, and B4
- piping (or ductwork) at locations between B6 through E6
- instrumentation taps at locations F3, F7, E2, E7, D3, D7 (two), and B6

The applicant responded that the components identified above are part of the secondary containment as shown by the flag "SC" on drawing LR-M-391, sheets 1 and 2, Rev. A. As such, the valve bodies, ductwork, and tubing are shown in Table 2.3.2-8 in LRA Section 2.3.2.8. The staff considered the applicant's response to the RAI acceptable since the components were subject to an AMR and were identified in Table 2.3.2-8 of the LRA. However, the applicant needs to indicate that valve bodies include damper housings for the SGTS dampers, if any, in LRA Table 2.3.2-7. This was part of Open Item 2.3.2.7.2-2. The additional part of this item is discussed in Section 2.3.2.8.2 of this SER.

In a letter dated November 26, 2002, the applicant provided the following clarification regarding valve bodies including damper housings for the SGTS dampers.

License renewal drawings LR-M-391, Sheets 1 and 2, Rev. A, show a portion of the SGTS and a portion of the secondary containment system that are in the scope of license renewal. System boundary flags delineate these two systems. The secondary containment system includes air-operated butterfly valves and does not include any dampers (P & ID symbols for butterfly valves and dampers are shown on LR-M-300 sheet 2). Therefore, LRA Table 2.3.2-8, Component Group Requiring Aging Management Review - Secondary Containment System, includes valves bodies but does not include damper enclosures. The SGTS includes both air-operated butterfly valves and dampers. Therefore, LRA Table 2.3.2-7, Component Groups Requiring Aging Management Review - Standby Gas Treatment System, includes both valve bodies and damper enclosures.

The NRC staff reviewed the applicant's response for the SGTS valve bodies and damper housings for the SGTS dampers and determined that LRA Table 2.3.2-7 includes these component group requiring an AMR. Therefore the SGTS part of Open Item 2.3.2.7.2-2 is closed.

In RAI 2.3.2.7-1(c), the staff requested that applicant clarify whether the housings for radiation detectors 430A/B/C/D and 432A/B/C/D at locations E3&E4 and F4&F5 on license renewal drawing LR-M-391, sheets 1 and 2, primary containment isolation and control (PBAPS Units 2 and 3) are within the scope of license renewal and subject to an AMR.

In response, the applicant stated that the subject radiation detectors are within the scope of license renewal. In accordance with NUREG-1800 and NEI 95-10, these radiation detectors are active and not subject to an AMR. These detectors are environmentally qualified instruments and are therefore addressed as a TLAA.

The staff agrees that the subject radiation detectors are active components, and as such are not subject to an AMR. The housings for these radiation detectors have a separate, passive pressure boundary intended function, and as such, could be considered as a separate component subject to an AMR. However, radiation detectors and their housings are typically tested, maintained, and replaced as a single integral unit. The staff therefore concurs with the applicant's conclusion that the housings for radiation detectors are not subject to an AMR.

On the basis of the above review the staff did not find any other omissions by the applicant of SSCs within the scope of license renewal.

2.3.2.7.3 Conclusions

On the basis of its review the staff concludes there is reasonable assurance that the applicant has adequately identified the standby gas treatment SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.2.8 Secondary Containment

2.3.2.8.1 Summary of Technical Information in the Application

In Section 2.3.2.8 of the LRA, the applicant identifies the components of the secondary containment system that fall within the scope of license renewal and are subject to an AMR. The details of the secondary containment are described in Sections 5.1 and 5.3 of the UFSAR for Peach Bottom Units 2 and 3. The boundaries of the secondary containment are shown in license renewal drawing LR-M-391, sheets 1 and 2, Rev. A.

The secondary containment system is an engineered safety feature system, consisting of mechanical components credited with maintaining the integrity of the secondary containment pressure boundary. This system includes components of the reactor building penetrations, components of the reactor building heating and ventilating system, and components of the standby gas treatment system (up to and including the second outboard isolation valve). The reactor building structure (refer to Section 2.4.2) is treated as a separate system from the secondary containment system. The LRA states that the reactor building penetrations are considered part of the reactor building structure; however, as explained below in the staff's evaluation, the applicant included them in Section 2.4.14 of the LRA, "Hazard barriers and Elastomers." The reactor building penetrations for piping, ventilation ducts, electrical cables, and instrument leads are sealed. The ventilation ducts are provided with valves for automatic closure when reactor building isolation is required. As the reactor building completely encloses the primary containment and auxiliary systems of the nuclear steam supply system, the secondary containment serves as the containment during reactor refueling when the primary containment is open and as an additional barrier when the primary containment is functional.

The initial scoping performed by the applicant has determined the following intended function for the secondary containment system to be within the scope of license renewal:

- Containment - The secondary containment system provides a secondary containment system boundary to contain any release of radioactive material outside the primary containment.

On the basis of the intended function identified above, the applicant identified secondary containment system components that are within the scope of license renewal. The applicant described its process for identifying the mechanical components subject to an AMR in Section 2.1.2 of the LRA. Based on this methodology, the applicant compiled a list of the component groups falling within the scope of license renewal and subject to an AMR. The applicant provided this list in Table 2.3.2-8 of the LRA. Table 2.3.2-8 identifies the following component groups and component types as falling within the scope of license renewal and subject to an AMR:

- casting and forgings (valve bodies)
- piping (tubing)
- sheet metal (ducting)

In Table 2.3.2-8, the applicant further states that pressure boundary is the only intended function associated with components of the secondary containment system that are subject to an AMR.

2.3.2.8.2 Staff Evaluation

The staff reviewed Section 2.3.2.8 of the LRA, Sections 5.1 and 5.3 of the Peach Bottom UFSAR, and license renewal drawings LR-M-391, sheets 1 and 2, Rev. A to determine whether there is reasonable assurance that the secondary containment system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components

having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

In a letter dated March 12, 2002, the staff requested additional information regarding the exclusion of certain secondary containment system components related to ventilation from the scope of license renewal. The applicant responded to the RAIs as discussed below.

In RAI 2.3.2.8-1, the staff stated that Section 2.3.2.8 of the LRA presents a summary description of the system functions, that evaluation boundary drawings highlight the evaluation boundaries of the secondary containment system, and that Table 2.3.2-8 lists components falling within the scope of license renewal and subject to an AMR. The corresponding drawings for this system in the UFSAR, however, show additional components that were not listed in Table 2.3.2-8 of the LRA. Specifically, the AMR results provided in Table 2.3.2-8 do not list damper housings (numerous locations) and test connections (locations E2, E7, D3 and D8), although these passive, long-lived components are shown on drawing LR-M-391, sheets 1 and 2, as falling within the scope of license renewal.

In a letter dated May 22, 2002, the applicant clarified that the components referred to by the staff as dampers in RAI 2.3.2.8-1 are actually air-operated valves. These valves are secondary containment isolation valves; their associated valve bodies are subject to an AMR and are listed in Table 2.3.2-8. Also, the applicant indicated that the test connections identified by the staff are considered to be in the ducting component group, which the applicant has included in the AMR results provided in LRA Table 2.3.2-8. The staff finds the applicant's RAI response to be acceptable, as it clarifies that the passive, long-lived components in question are subject to an AMR in accordance with 10 CFR 54.21(a)(1). However, the applicant needs to indicate that valve bodies include the damper housings for the secondary containment system dampers, if any (as shown in LRM-391), in LRA Table 2.3.2-8. This was the other part of Open Item 2.3.2.7.2-2.

In a letter dated November 26, 2002, the applicant clarified that License renewal drawings LR-M-391 sheets 1 and 2 show a portion of the SGTS and a portion of the secondary containment system that are in the scope of license renewal. System boundary flags delineate these two systems. The secondary containment system includes air-operated butterfly valves and does not include any dampers. Therefore, LRA Table 2.3.2-8, Component Group Requiring Aging Management Review - Secondary Containment System, includes valves bodies but does not include damper enclosures.

The NRC staff reviewed the applicant's response and agrees with the clarification that the secondary containment system does not have any dampers and, therefore, the damper housing for the dampers need not to be addressed for an AMR. Based upon the above, the other part of secondary containment system Open Item 2.3.2.7.2-2 is closed.

In RAI 2.3.2.8-2, the staff stated that neither Section 2.3.2.8 nor Section 2.4.2 of the LRA listed penetration components described in the UFSAR. LRA Section 2.3.2.8, which describes the secondary containment system, states that secondary containment penetrations are considered part of the reactor building structure. However, LRA Table 2.4-2, which lists components of the reactor building structure that are within the scope of license renewal and subject to an AMR, does not list secondary containment penetrations, nor does the associated discussion in

Section 2.4.2 justify their exclusion. Therefore, the staff issued RAI 2.3.2.8-2 to ascertain whether the applicant properly addressed the secondary containment penetrations in the LRA.

In a response dated May 22, 2002, the applicant verified that all secondary containment penetrations fall within the scope of license renewal and are treated as hazard barrier components. As such, the secondary containment penetrations are included in LRA Table 2.4-14 as hazard barriers and in LRA Table 3.5-14 for aging management. The staff found this response to be acceptable, as it clarifies that all secondary containment penetrations are within the scope of license renewal and subject to an AMR.

On the basis of the above review the staff did not find any other omissions by the applicant of SSCs within the scope of license renewal.

2.3.2.8.3 Conclusions

On the basis of its review the staff concludes there is reasonable assurance that the applicant has adequately identified the secondary containment SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.3 Auxiliary Systems

In Section 2.3.3, "Auxiliary Systems (AUX)," of the Peach Bottom Atomic Power Station, Units 2 & 3, License Renewal Application (the LRA), Exelon (the applicant) described the systems, structures and components (SSCs) of the AUX that are subject to aging management review (AMR) for license renewal.

2.3.3.1 Fuel Handling Systems

2.3.3.1.1 Summary of Technical Information in the Application

In Section 2.3.3.1, "Fuel Handling Systems," of the LRA, the applicant describes the structural components of the fuel handling systems that are within the scope of license renewal and subject to an AMR. Additional information concerning fuel handling systems is given in Sections 10.3 and 10.4 of the Peach Bottom UFSAR.

In Section 2.1 of the LRA, the applicant described its process for identifying the structural/civil components within the scope of license renewal and subject to an AMR. Based on its methodology, the applicant, in Table 2.2-1 identifies the fuel handling system components within the scope of license renewal and describes the results of its scoping methodology in Section 2.3.3.1 of the LRA.

As stated in Section 10.4.2, "Fuel Servicing Equipment," of the Peach Bottom UFSAR, the fuel preparation machines located in each fuel storage pool are used to remove and install channels to support inspection or servicing of fuel assemblies. The fuel preparation machines are also used for the placement of new fuel assemblies into the spent fuel pool. These machines are designed to be removed from the pool for servicing. In addition, Section 10.4.6, "Refueling Equipment," describes the use and purposes of the refueling platform. The refueling platform is used primarily as a means of transporting fuel assemblies back and forth between the reactor well and the storage pool. The platform travels on rails extending along each side of the reactor well and fuel pool. The platform supports the fuel grapple and the frame-mounted and monorail auxiliary hoists. Platform operations are controlled from either auxiliary hoist control pendants or refuel grapple controller consoles. Other cranes and hoists used during refueling operations, including the fuel channel handling hoists, the control rod drive (CRD) jib crane and the reactor building crane, are discussed in LRA Section 2.3.3.18, "Cranes and Hoists."

The applicant's scoping methodology captures fuel handling systems within the scope of license renewal that meet the intent of 10 CFR 54.4(a) because they perform the following "structure level" intended function:

- Maintain structural integrity - Maintain structural integrity of the refueling platform and the fuel preparation machines.

On the basis of the function identified above, the applicant identified the fuel handling systems components that are within the scope of license renewal. Table 2.3.3-1 lists the following component groups and structural components that are subject to an AMR:

- fuel preparation machines
- refueling platform (assembly)
- refueling platform (rails)
- refueling platform (mast)

SCs of the component groups listed within Table 2.3.3-1 perform a structural support intended function. As a result, SCs of the fuel handling systems within the scope of license renewal perform their intended functions without moving parts or without change in configuration or properties, and are not subject to periodic replacement based on a qualified life or specified time limit.

2.3.3.1.2 Staff Evaluation

The staff reviewed Section 2.3.3.1 of the LRA and Sections 10.3 and 10.4 of the Peach Bottom UFSAR to determine whether there is reasonable assurance that the fuel handling system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

The staff reviewed the structural component groups in Table 2.3.3-1 (i.e., fuel preparation machines, refueling platform, rails, and mast) to determine whether there were any other components associated with the fuel handling systems that meet the scoping criteria of 10 CFR 54.4(a), but were not included within the scope of license renewal. The staff has reviewed Section 2.3.3.1 of the LRA and the various sections of the UFSAR pertaining to the fuel handling systems. The staff also examined the component groupings listed in Table 2.3.3-1 in the LRA to determine whether they are the only SCs that are subject to an AMR in accordance with 10 CFR 54.21(a)(1).

On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.3.3.1.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the fuel handling SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.3.2 Fuel Pool Cooling and Cleanup System

2.3.3.2.1 Summary of Technical Information in the Application

In Section 2.3.3.2 of the LRA, the applicant describes the components of the fuel pool cooling and cleanup system falling within the scope of license renewal and subject to an AMR. This system is further described in Section 10.5 of the Peach Bottom UFSAR.

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. An interconnection with the RHR system provides backup cooling and makeup water to the fuel storage pool.

The system consists of three fuel pool cooling pumps, three heat exchangers, filter-demineralizers, two skimmer surge tanks, and associated piping, valves, and instrumentation. 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. The filter-demineralizers are located in the radwaste building.

The pumps circulate fuel pool water in a closed loop, taking suction from the skimmer surge tanks through the heat exchangers, circulating the water through the filter-demineralizers, and directing the processed fuel pool water back into the pool and reactor well.

The applicant described its methodology for identifying the mechanical components within the scope of license renewal in Section 2.1.2 of the LRA. The applicant stated that only the safety-related path for providing makeup water for the fuel pool in the event of a loss of fuel pool inventory when normal makeup is not available is within the scope of license renewal.

Using the methodology described in LRA Section 2.1.2, the applicant listed the mechanical component groups subject to an AMR and identified their intended functions in Table 2.3.3-2 of the LRA. Table 2.3.3-2 identifies the following component groups and component types:

- casting and forging (valve bodies)
- piping (pipe)
- piping specialties (vacuum breakers and restricting orifices)

The intended function for the fuel pooling cooling and cleanup system components subject to an AMR is pressure boundary integrity.

2.3.3.2.2 Staff Evaluation

The staff reviewed Section 2.3.3.2 of the LRA and the associated sections of the UFSAR for Peach Bottom to determine whether there is reasonable assurance that the fuel pool cooling and cleanup system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that are required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

The staff reviewed the text and diagrams submitted by the applicant in Section 2.3.3.2 of the LRA and the Peach Bottom UFSAR to determine if the applicant adequately identified the SSCs of the fuel pool cooling and cleanup system that are in the scope of license renewal. The staff verified that those portions of the fuel pool cooling and cleanup system that meet the scoping requirements of 10 CFR 54.4 are included within the scope of license renewal and are identified as such by the applicant in Section 2.3.3.2 of the LRA. The staff then focused its review on those portions of the fuel pool cooling and cleanup system that were not identified as being within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4. The staff also reviewed the UFSAR to determine if there were any additional system functions that were not identified in the LRA, and verified that those additional functions did not meet the scoping requirements of 10 CFR 54.4.

The staff then determined whether the applicant had properly identified the SSCs that are subject to an AMR from among those portions of the fuel pool cooling and cleanup system that are identified as being within-scope of license renewal. The applicant identifies and lists the SSCs subject to AMR for the Fuel Pool Cooling and Cleanup system in Table 2.3.3-2 of the LRA using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff performed its review by sampling the SSCs that the applicant determined to be within the scope of license renewal but not subject to AMR to verify that these SSCs performed their intended functions with moving parts or with a change in configuration or properties and were subject to replacement base on a qualified life or specified time period.

The applicant identified the portions of the fuel pool cooling and cleanup system that are within-scope of license renewal in the drawings referenced in the LRA. The detailed flow diagrams were highlighted to identify those portions of the system that are within the scope of license renewal. The applicant highlighted those components which it believes perform at least one of the scoping requirements of 10 CFR 54.4. The staff compared the LRA flow diagrams to the system drawings and the descriptions in the UFSAR to ensure they were representative of the fuel pool cooling and cleanup system. The staff sampled portions of the flow diagram that were not highlighted to verify that these components did not meet any of the scoping criteria in 10 CFR 54.4.

By letter dated March 12, 2002, the staff requested the following additional information regarding the fuel pool cooling and cleanup system.

On license renewal boundary drawing LR-M-363, sheets 1 and 2, a spool piece (location E2) and reducers and increasers (location F2) are shown as falling within the scope of license renewal. However, these particular components are not specifically listed in Table 2.3.3-2 of the LRA as being subject to an AMR. In RAI 2.3.3.2-1, the staff asked the applicant to indicate whether these piping components are included in the scope of license renewal and subject to an AMR. In a letter dated May 22, 2002, the applicant stated that components such as reducers and increasers are fittings and are part of the piping component group, and therefore are within the scope of license renewal and subject to an AMR. Based on the above clarification, the staff found the applicant's response to RAI 2.3.3.2-1 to be acceptable.

On drawing LR-M-363, sheets 1 and 2, in the fuel storage pool, there is an unidentified component indicated by a circle at location F4. The staff believes that this component may perform one or more intended functions, such as pressure boundary, which justify its inclusion within the scope of license renewal. However, this component is not identified on the legend (drawing LR-M-300). In RAI 2.3.3.2-2, the staff asked the applicant to identify this component and indicate where in the LRA it is included within the scope of license renewal and subject to an AMR. In a letter dated May 22, 2002, the applicant clarified that the "hole" on the drawing is not a component, but represents two siphon breaker holes to prevent siphoning of water. The staff considers the clarification provided in the applicant's response to RAI 2.3.3.2-2 to be acceptable.

In Table 2.3.3-2 of the LRA, a restricting orifice is listed as a component requiring an AMR. However, pressure boundary is the only intended function listed for this component. In RAI 2.3.3.2-3, the staff questioned whether flow restriction should also be listed as an intended function for this component. In a letter dated May 22, 2002, the applicant stated that the restricting orifice was installed in the RHR to fuel pool discharge line during plant construction to give a pressure drop large enough to prevent the upstream valves from vibrating open. However, the addition of RHR pump discharge control valves, after the original plant construction, provides sufficient flow control that the restricting orifice is no longer needed. Therefore, the restricting orifice is not required to provide the flow restriction (throttle) intended function. The staff found the applicant's exclusion of the flow restriction intended function of this component from the scope of license renewal to be acceptable, as the component does not perform a flow restricted intended function; however, it does perform a pressure boundary intended function that meets the criteria of 10 CFR 54.21(a)(1).

On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.3.3.2.3 Conclusions

On the basis of its review, the staff concludes that there is reasonable assurance that the applicant has adequately identified the fuel pool cooling and cleanup system SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.3.3 Control Rod Drive System

2.3.3.3.1 Summary of Technical Information in the Application

As described in the LRA, 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.

Intended functions within the scope of license renewal:

CRD scram - The control rod drive system provides rapid control rod insertion in the core upon receipt of an automatic or manual scram signal.

Alternate rod insertion - The alternate rod insertion feature of the CRD system reduces the probability of an ATWS event by providing an alternate means to scram the reactor.

Table 2.3.3-3 of the LRA identified the component groups requiring aging management review. The component groups which were identified for the CRD include: valve bodies, filter bodies, piping, tubing, rupture discs, and accumulators.

2.3.3.3.2 Staff Evaluation

The staff reviewed Section 2.3.3.3 of the LRA and the associated sections of the UFSAR to determine whether there is reasonable assurance that the CRD system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

After completing the initial review, by letter dated March 1, 2002, the staff requested the applicant to provide additional information on the CRD system. By the letter dated May 6, 2002, the applicant responded to staff’s request for additional information (RAI) as discussed below.

The staff understands that the control rod drop accident is a design basis event for Peach Bottom, and that in the CLB it is assumed that the control rod drive is fully withdrawn before the stuck rod falls out of the core at a maximum velocity of 5 ft/sec. According to Section 1.6.2.13 of the UFSAR, the control rod velocity limiter, an engineered safeguard, limits the rod drop velocity to less than this value, and the velocity limiters contain no moving parts. Furthermore, the staff understands that the limiter is relied on to keep the resultant doses due to radioactive material release below the guideline values of 10 CFR Part 100. One of the required functions designated in the rule for safety-related SSCs, as delineated in 10 CFR 54.4(a)(1)(iii), is the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the 10 CFR Part 100 guidelines. It appears that the subject components were not identified in the LRA, and therefore in RAI 2.3.3-1, the staff requested the applicant to either include the subject components within the scope of license renewal requiring an AMR or submit a basis for concluding that the components are not in-scope. In response, the applicant stated that the control rod velocity limiter is part of the control rod blade, which is short-lived and therefore is not subject to aging management review requirements. The staff find the applicant's response acceptable because the control rod velocity limiter is periodically replaced and therefore not subject to an AMR.

Section 1.6.2.14 of the UFSAR states that the CRD housing supports (CRDHSs) limit the travel of a control rod in the event that a control rod housing is ruptured. The supports prevent a nuclear excursion as a result of a housing failure, thus protecting the fuel barrier and limiting radioactive releases. In addition, Section 3.4.6.4 of the UFSAR states that following a postulated failure of the drive housing at the attachment weld at the same time the control rod is withdrawn, and if the collet were to stay unlatched, the housing would separate from the vessel, and the drive and housing would be blown downward against the CRDHS. Since credit is taken for the CRDHSs, and the CRDHSs are passive and long-lived, the staff believes that the subject components should be within the scope of license renewal and require aging management. It appears, however, that the subject components and their intended function of limiting travel of the control rod following control rod housing rupture have not been identified in the LRA. Therefore in RAI 2.3.3-2, the staff requested the applicant to provide an explanation. In response, the applicant clarified that the CRD housing supports are included in the scope of license renewal and subject to aging management review. The supports are not listed separately in the LRA, but included in the component support commodity group described in Section 2.4.13 of the LRA. The applicant further stated that this approach is consistent with NUREG-1800, wherein CRD housing supports are not listed separately. The staff finds the applicant's response acceptable because CRDHS are within the scope of license renewal and subject to an AMR.

On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.3.3.3.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the CRD SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.3.4 Standby Liquid Control System

2.3.3.4.1 Summary of Technical Information in the Application

The purpose of the standby liquid control (SLC) 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 consists of 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 system is manually initiated from the control room via a three-position key-locked selector switch.

Intended functions within the scope of license renewal:

Reactivity control - The standby liquid control system injects sodium pentaborate solution into the reactor vessel in sufficient quantity and concentration to bring the reactor from rated power to a cold shutdown at any time in core life.

Table 2.3.3-4 of the LRA identified the component groups requiring aging management review. The component groups which were identified for the SLC system include: valve bodies, pump casings, piping, tubing, thermowells, accumulators, and solution tank.

2.3.3.4.2 Staff Evaluation

The staff reviewed Section 2.3.3.4 of the LRA and the associated sections of the UFSAR to determine whether there is reasonable assurance that the SLC system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule.

On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.3.3.4.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the SLC SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.3.5 High-Pressure Service Water System

2.3.3.5.1 Summary of Technical Information in the Application

In Section 2.3.3.5 of the LRA, the applicant describes the components of the high-pressure service water (HPSW) system falling within the scope of license renewal and subject to an AMR. This system is further described in Section 10.7 of the Peach Bottom UFSAR.

The HPSW system provides cooling water for the residual heat removal system (RHR) heat exchangers under normal, hot standby, refueling, and postaccident conditions. The system provides core decay heat removal capability during shutdown periods, and containment cooling during normal operations and during post-accident conditions.

The HPSW system consists of four pumps and the necessary piping, valves and controls. During normal operation, HPSW cooling water suction is from the Conowingo Pond, and the system discharge is to the discharge pond through one pipe for each unit. During emergency situations, the HPSW operates in conjunction with the emergency cooling tower and suction is from the HPSW pump bay, which is fed by the emergency cooling tower basin. The HPSW pumps deliver cooling water at a pressure greater than RHR system pressure. This inhibits radioactive leakage from the RHR system to the environs. Radioactivity in the HPSW system is monitored upstream and downstream of the RHR heat exchangers to detect activity in potential release paths.

The following intended function was identified as falling within the scope of license renewal:

- RHR heat sink - The HPSW system provides cooling water flow to transfer heat from the RHR heat exchangers for the normal operation, post-accident shutdown, hot standby, and refueling modes of operation.

Using the methodology described in LRA Section 2.1.2, as specified in 10 CFR 54.21(a)(1), the applicant compiled a list of the mechanical component groups subject to an AMR and identified their intended functions in Table 2.3.3-5 of the LRA. Table 2.3.3-5 identifies the following component groups and component types as falling within the scope of license renewal and subject to an AMR:

- casting and forging (valve bodies, pump casings, strainer bodies, strainer screens)
- heat exchanger (pump motor oil cooler)
- piping (pipe, tubing)
- piping specialties (restricting orifice, flow elements)

All of the HPSW components identified above (except strainer screens) have a pressure boundary intended function. Strainer screens have a filter intended function. In addition to the pressure boundary intended function, the HPSW pump motor oil cooler has a heat transfer intended function and the restricting orifice has a throttle intended function.

2.3.3.5.2 Staff Evaluation

The staff reviewed Section 2.3.3.5 of the LRA and Section 10.7 of the Peach Bottom UFSAR to determine whether there is reasonable assurance that the HPSW system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

The staff verified that those portions of the HPSW system that meet the scoping requirements of 10 CFR 54.4 are included within the scope of license renewal and are identified as such by the applicant in Section 2.3.3.5 of the LRA. The staff then focused its review on those portions of the HPSW system that were not identified as being within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4. The staff also reviewed the UFSAR to determine if there were any additional system functions that were not identified in the LRA, and verified that those additional functions did not meet the scoping requirements of 10 CFR 54.4.

The staff then determined whether the applicant had properly identified the SSCs that are subject to an AMR from among those portions of the HPSW system that are identified as being within-scope of license renewal. The applicant identifies and lists the SSCs subject to AMR for the HPSW system in Table 2.3.3-5 of the LRA using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff performed its review by sampling the SSCs that the applicant determined to be within the scope of license renewal but not subject to AMR to verify that these SSCs performed their intended functions with moving parts or with a change in configuration or properties and were subject to replacement base on a qualified life or specified time period.

The applicant identified the portions of the HPSW system that are within-scope of license renewal in the drawings referenced in the LRA. The detailed flow diagrams were highlighted to identify those portions of the system that are within the scope of license renewal. The applicant highlighted those components which it believes perform at least one of the scoping requirements of 10 CFR 54.4. The staff compared the LRA flow diagrams to the system drawings and the descriptions in the UFSAR to ensure they were representative of the HPSW system. The staff sampled portions of the flow diagram that were not highlighted to verify that these components did not meet any the scoping criteria in 10 CFR 54.4.

By letter dated March 12, 2002 the staff requested additional information regarding the HPSW system. In a letter dated May 22, 2002, the applicant responded to the two staff RAIs discussed below.

RAI 2.3.3.5-1 asked the applicant to justify the omission of the HPSW intended function of inhibiting leakage of radioactive material from the RHR system to the environment, as identified in Section 10.7.4 of the UFSAR.

In response to RAI 2.3.3.5-1, the applicant stated that the function of the HPSW system to inhibit leakage of radioactive material from the RHR system to the environment is a power generation design basis function, and not a safety-related intended function of the HPSW system, as indicated in Section 10.7.4 of the UFSAR. The staff reevaluated Section 10.7.4 of the UFSAR and determined that the function of the HPSW system to inhibit leakage of radioactive material is not relied on to mitigate the consequences of a design basis accident. Therefore, the staff finds the applicant's response to RAI 2.3.3.5-1 to be acceptable, as this function does not meet the criteria of 10 CFR 54.21(a)(1).

In RAI 2.3.3.5-2, the applicant was asked to justify the exclusion of the HPSW radiation monitors and the tubing which delivers fluid to the monitors from within the scope of license renewal and subject to an AMR. The staff referenced Section 10.7.5 of the UFSAR, which states that under abnormal operating conditions, RHR pressure could exceed HPSW system pressure. An RHR heat exchanger leak under these abnormal conditions would result in radioactive RHR water migrating into the HPSW system and into the river. To limit the release of radioactive water to the river from this potential release path, signals from the radiation monitors in the system which sample the HPSW system upstream and downstream of the RHR heat exchangers initiate an alarm in the control room at a predetermined radiation level. Although the HPSW system radiation monitors can be isolated by closing valves (e.g., valve 63H23452A shown on drawing LR-M-315, sheet 1, at location C8), the valves in the tubing to the radiation monitors appear to be normally open, so the tubing and radiation monitors also serve a pressure boundary function.

The applicant responded to RAI 2.3.3.5-2 by stating that the HPSW system radiation monitors are not safety-related and do not have any safety-related intended functions. These radiation monitors are designed to provide operators with an indication of a potential heat exchanger tube leak. The HPSW system radiation monitoring system is a process liquid radiation monitoring system (UFSAR Section 7.12.4) and is provided to indicate when operational limits for the normal release of radioactive material to the environs are being approached, and to indicate process system malfunctions by detecting the presence of radioactive material in a normally uncontaminated system. These radiation monitors provide a clear indication to operations personnel whenever the radioactivity level approaches or exceeds preestablished operational limits for the discharge of radioactive material to the environs. This function is associated with normal plant operation, and is not required to mitigate the consequences of accidents that could result in potential offsite exposure comparable to the 10 CFR Part 100 guidelines.

The applicant also stated that the HPSW radiation monitoring system 1-inch piping downstream of the boundary isolation valves is not safety-related. Potential flow diversion due to a postulated failure of this small diameter piping would not have a significant impact on the flow through the 18-inch diameter HPSW system piping, and closing the boundary isolation valves can easily isolate the 1-inch piping. The staff found the applicant's response to RAI 2.3.3.5-2 acceptable on the basis that the HPSW radiation monitoring system is not required for monitoring radioactive material releases comparable to 10 CFR Part 100 guidelines. Also, the failure of the HPSW piping leading to the radiation monitoring system will not impact the intended function of the HPSW system. Therefore, HPSW radiation monitors and the associated piping do not have any safety-related intended functions that fall within the scope of license renewal as stated in 10 CFR 54.21(a)(1).

On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.3.3.5.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the HPSW SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.3.6 Emergency Service Water System

2.3.3.6.1 Summary of Technical Information in the Application

In Section 2.3.3.6 of the LRA, the applicant describes the components of the emergency service water (ESW) system falling within the scope of license renewal and subject to an AMR . The ESW system is further described in UFSAR Section 10.9.

The ESW system provides a reliable supply of cooling water to diesel generator coolers, emergency core cooling system and reactor core isolation cooling compartment air coolers, core spray pump motor oil coolers, and other selected equipment during a loss of offsite power or during a loss of normal station service water.

The system consists of two 100%-capacity ESW pumps and the associated discharge and distribution piping, piping components, valves, and instrumentation and controls. The two ESW pumps take suction from individual pump bays within the circulating water pump structure. 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 ESW system provides the cooling water whenever the pumps are operating and the ESW system pressure is greater than service water system pressure or the service water system is manually isolated from the ESW system. In the event of extreme high or low Conowingo Pond level, the ESW system can be shifted to closed-cycle operation through the use of the emergency cooling water system.

The following is the intended function of the ESW system identified as falling within the scope of license renewal:

- Component cooling - The ESW system provides cooling water flow to transfer heat from certain safety-related equipment during a loss of offsite power or maximum credible accident via either an open loop or a closed loop configuration.

Using the methodology described in LRA Section 2.1.2, the applicant compiled a list of the mechanical component groups subject to an AMR and identified their intended functions in Table 2.3.3-6 of the LRA. Table 2.3.3-6 identifies the following component groups and component types as falling within the scope of license renewal and subject to an AMR:

- casting and forging (valve bodies, pump casings)
- piping (pipe, tubing)
- piping specialties (thermowells, flow elements, expansion joints)

All of the ESW components identified above have a pressure boundary intended function.

2.3.3.6.2 Staff Evaluation

The staff reviewed Section 2.3.3.6 of the LRA and Section 10.9 of the UFSAR to determine whether there is reasonable assurance that the ESW system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

The staff verified that those portions of the ESW system that meet the scoping requirements of 10 CFR 54.4 are included within the scope of license renewal and are identified as such by the applicant in Section 2.3.3.6 of the LRA. The staff then focused its review on those portions of the ESW system that were not identified as being within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4. The staff also reviewed the UFSAR to determine if there were any additional system functions that were not identified in the LRA, and verified that those additional functions did not meet the scoping requirements of 10 CFR 54.4.

The staff then determined whether the applicant had properly identified the SCs that are subject to an AMR from among those portions of the ESW system that are identified as being within-scope of license renewal. The applicant identifies and lists the SCs subject to AMR for the ESW system in Table 2.3.3-6 of the LRA using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff performed its review by sampling the SCs that the applicant determined to be within the scope of license renewal but not subject to AMR to verify that these SCs performed their intended functions with moving parts or with a change in configuration or properties and were subject to replacement base on a qualified life or specified time period.

The applicant identified the portions of the ESW system that are within the scope of license renewal in the drawings referenced in the LRA. The detailed flow diagrams were highlighted to identify those portions of the system that are within the scope of license renewal. The applicant highlighted those components which it believes perform at least one of the scoping requirements of 10 CFR 54.4. The staff compared the LRA flow diagrams to the system drawings and the descriptions in the UFSAR to ensure they were representative of the ESW system. The staff sampled portions of the flow diagram that were not highlighted to verify that these components did not meet any the scoping criteria in 10 CFR 54.4.

In a letter dated March 12, 2002, the staff requested additional information regarding the ESW system, as discussed below.

In RAI 2.3.3.6-1, the staff asked the applicant to clarify the location of the boundary between the normal service water (NSW) system and the ESW system. According to NUREG/CR-4550, Vol. 4, Rev. 1, Part 3 (page 4.3-5), a LOCA in the NSW system, where the piping interfaces with the ESW system, would cause the ESW to feed the break instead of cooling certain safety system loads. That is, a rupture of the NSW piping in a post-accident condition could cause the ESW (an in-scope system) to fail to perform its intended safety function. The drawings for the ESW system (LR-M-315) did not indicate the boundary between the ESW and NSW systems, so it cannot be determined whether the section of piping referred to in NUREG/CR-4550 has been recategorized to the ESW system.

In a letter dated May 22, 2002, the applicant stated that the boundary between the Unit 2 non-safety-related service water system and the safety-related emergency service water (ESW) system is shown on drawing LR-M-315, sheet 5, at zone H-2. The interface boundary is at the safety-related ESW system check valve 2-33-514, which is included in the scope of license renewal. This check valve prevents flow from the ESW system to the non-safety-related service water system in the event of a pipe rupture in the non-safety-related service water system. The ESW system side of the check valve is ESW piping, so non-safety-related service water piping is not recategorized to the ESW system.

The applicant further explained that the boundary between the Unit 3 non-safety-related service water system and the safety-related emergency service water (ESW) system is shown on drawing LR-M-315, sheet 4, at zone F-8. The interface boundary is at the safety-related ESW system check valve 3-33-514, which is included in the scope of license renewal. This check valve prevents flow from the ESW system to the non-safety-related service water system in the event of a pipe rupture in the non-safety-related service water system. The ESW system side of the check valve is ESW piping, so non-safety-related service water piping is not re-categorized to the ESW system.

The staff finds the applicant's response to RAI 2.3.3.6-1 to be acceptable because a failure in the non-safety-related service water system will not cause the safety-related ESW system to fail to perform its intended safety-related function. In addition, the drawings cited in the applicant's response to RAI 2.3.3.6-1 adequately identify the boundaries between the safety-related ESW system and the non-safety-related service water system.

On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.3.3.6.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the ESW SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.3.7 Fire Protection System

2.3.3.7.1 Summary of Technical Information in the Application

In Section 2.3.3.7 of the LRA, the applicant describes the components of the fire protection system (FPS) and fire protection program (FPP) that fall within the scope of license renewal and are subject to an AMR. Section 2.1.2 of the LRA contains the system and structure scoping criteria and identifies the scoping criteria for fire protection SSCs required to demonstrate compliance with 10 CFR 50.48 in accordance with 10 CFR 54.4(a)(3). License renewal boundary drawings referenced for the FPS are LR-M-318 and LR-M-323, both Rev. A.

At Peach Bottom, the term "fire protection system" refers to the integrated complex of components and equipment provided for the detection and suppression of fires. The FPS is described in the Peach Bottom Fire Protection Program (FPP).

The FPP contains information on how regulatory commitments are met through analyses and plant evaluations. The FPP includes the concepts of design and layout implemented to prevent or mitigate fires, administrative controls and procedures, and personnel training. The FPP uses a defense-in-depth approach aimed at preventing fires, minimizing the effect of any fires that occur, providing appropriate fire detection and suppression equipment, and training personnel in fire prevention and fire fighting. The purpose of the FPP at Peach Bottom is to ensure that a fire will not prevent the safe plant shutdown systems from performing their necessary intended functions. The FPP is addressed in Sections 2.3.3.7 and 2.4.14 of the LRA.

The FPS is designed to detect the presence of smoke or excessive heat in designated plant areas, provides local alarms, a control room annunciation horn and printed record, and suppression system activation. The FPS includes various types of water, foam, and carbon dioxide suppression systems.

Heat and smoke detectors are installed in designated plant areas where fire hazards exist and in all areas containing safety-related equipment, except where a specific exemption was granted by the NRC. Detection of fire by any smoke or heat detector will activate an audible control room alarm with visual annunciation and a printed record of the event.

There are two vertical turbine fire pumps, each rated for 2,500 gpm at 125 psig total head. The lead pump is electric-motor-driven, and the 100% capacity backup pump is diesel-engine-driven. The pumps and their controllers are UL-listed. The system is capable of supplying water at the required pressure for the largest sprinkler flow plus 500 gpm. The source of water for the Peach Bottom FPS is Conowingo Pond. This source allows continuous operation of either pump as long as required. The fire pumps take suction from independent, isolatable intake basins. Check valves are installed at the pump discharges to prevent water from one source from being pumped into the other source. The fire pumps also provide water to the foam systems.

Total flooding CO_2 systems are provided for the cable spreading room, computer room, high-pressure coolant injection (HPCI) pump rooms, and high-pressure turbine bearing lube oil pumps. These systems are supplied from two 6-ton storage tanks. The total flooding CO_2 systems for the diesel generator bays are supplied by one 2.75-ton storage tank. The design concentrations for the total flooding CO_2 systems are 34% for the HPCI pump rooms, computer room, and diesel generator bays, and 50 percent for the cable spreading room. These low-pressure CO_2 tanks also supply hose reels on the east side of the turbine enclosure operating deck.

The initial scoping of the fire protection system at Peach Bottom was performed on the basis of the intended functions listed below. A separate fire safe shutdown (FSS) system was designated to capture certain active electrical components, fire barriers, and panels associated with the fire safe shutdown analysis for the purposes of license renewal. These components were realigned to the FSS system from the drywell ventilation system, the substations and transformers system, and the 13 kV system. The components of the FSS system are scoped and screened as commodities in LRA, and identified in Section 2.3.3.7.2 below.

LRA Section 2.3.3.7 lists the following intended functions of the fire protection system within the scope of license renewal:

- Fire protection (detection, suppression, containment, standby) - The fire protection system provides methods to detect, suppress, contain, and monitor fire events.

On the basis of the intended functions identified above, the applicant identified the FPS components that fall within the scope of license renewal. The applicant described its process for identifying the mechanical components subject to an AMR in Section 2.1.2 of the LRA. Based on this methodology, the applicant compiled a list of the components groups within the scope of license renewal and subject to AMR. The applicant provided this list in Table 2.3.3-7 of the LRA. The applicant identified the following five component groups as falling within the scope of license renewal and subject to an AMR in Table 2.3.3-7 of the LRA:

- castings and forgings (valve bodies, sprinkler heads, pump casings, strainer bodies, strainer screens, hydrants)
- elastomer (flexible hoses)
- piping (pipe, tubing, fittings)
- piping specialities (discharge nozzles, strainer bodies, strainer screens, restricting orifice, flow elements, metal flex connection)
- vessel (carbon dioxide tank, fuel tank, muffler)

Table 2.3.3-7 lists pressure boundary as the intended function for most of the fire protection components listed above. Strainer screens have a filter intended function, restricting orifices have a throttle intended function, and sprinkler heads and discharge nozzles also have a spray intended function.

2.3.3.7.2 Staff Evaluation

The staff reviewed Section 2.3.3.7 of the LRA, the associated section of the UFSAR, and the FPP to determine whether there is reasonable assurance that the fire protection system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that are required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

The staff sampled portions of the Peach Bottom FPP which contain the plant commitments and safety evaluations which form the CLB for the FPS. The staff then compared a sample of the FPS and components identified in the FPP to the license renewal drawings to verify that required components were identified as falling within the scope of license renewal. The staff also compared SSCs identified in NRC-approved SERs, which document Peach Bottom’s compliance with the provisions of Appendix A to BTP 9.5-1, to the FPS license renewal drawings to verify that no additional required portions of the FPS were outside of the evaluation boundary, as reflected in staff fire protection safety evaluation reports.

Programs to manage the aging of fire hoses, extinguishers, and air packs are described in the Peach Bottom fire protection plan. In accordance with plant technical specifications and Section 3.3.2, item 81, of the FPP, the fire hoses meet the requirements of NFPA 14. They are tested annually and are repaired or replaced as necessary. Portable fire extinguishers are provided as described in FPP Section 2.11 and are installed and maintained in accordance with NFPA 10 and 10A. Breathing apparatuses are provided for fire brigade use as described in Section 3.1, item 43, of the FPP. The staff considers the applicant's treatment of these items acceptable as they are replaced on the basis of condition, consistent with the guidance given to the staff in the March 10, 2000, letter from C. I. Grimes, NRC, to D. J. Waters, NEI, entitled "License Renewal Issue No. 98-12, 'Consumables.'"

The applicant has adequately demonstrated how it was able to include components from the Peach Bottom SER dated September 16, 1993, in the scoping methodology by using the FPP as the primary scoping document for fire protection.

After the staff's initial review of the LRA, the staff identified several concerns with the scoping and screening of FPS components required for compliance with 10 CFR 50.48. The staff noted that several fire protection components listed in the SER, including the fire detection and alarm system, which were excluded from the scope of license renewal are required for compliance with 10 CFR 50.48. These concerns led to the issuance of RAIs, which were sent to the applicant in a letter dated March 12, 2002. The applicant responded to the RAIs in a letter dated May 22, 2002, as discussed below.

RAI 2.2-1.1b requested the applicant to identify components have been realigned from out-of-scope systems to the fire safe shutdown system and other systems listed in the RAI. The applicant responded that the fire safe shutdown system was designated to capture certain components associated with the fire safe shutdown analysis for the purposes of license renewal. Components realigned to the fire safe shutdown system include certain active electrical components, fire barriers, and panels associated with the fire safe shutdown analysis. Cables for temperature monitoring instrumentation used during postulated fire safe shutdown events were realigned from the drywell ventilation system. These cables are addressed in LRA Table 2.5-1. In-scope panels that were realigned from the substations and transformers system are addressed in LRA Table 2.4.16, and in-scope panels realigned from the 13 kV system are addressed in LRA Table 2.4.16. The staff finds the clarification provided to be acceptable.

In RAI 2.3.3.7-1, the staff requested that the applicant verify that the fire protection criteria contained in Branch Technical Position (BTP) Auxiliary and Power Conversion Systems Branch (APCSB) 9.5-1 and related SERs were considered in the scoping and screening process. In a letter dated May 22, 2002, the applicant responded that LRA Section 2.1.2.1, page 2-9, states: "Compliance with 10 CFR 50.48 is documented in the Fire Protection Program (FPP) that is part of the PBAPS UFSAR." The Peach Bottom FPP describes the fire protection features of the plant necessary to comply with BTP APCSB 9.5-1, Appendix A, and makes reference to the SER and its four supplements and also to the SER of September 16, 1993, for the Peach Bottom FPP, through Revision 4. The fire protection features of the plant necessary to comply with BTP APCSB 9.5-1, Appendix A, and the referenced SERs were used to identify those SSCs relied on to demonstrate compliance with 10 CFR 50.48, as stated in Section 2.1.2.1 of the scoping and screening methodology.

The staff reviewed the applicant's response to RAI 2.3.3.7-1. The staff agrees with the applicant's contention that the FPS scoping included all the fire protection SSCs required to meet the commitments outlined in the FPP intended to meet the requirements of 10 CFR 50.48(b)(1)(i). The staff finds the applicant's response acceptable, on the basis that the 10 CFR 50.48 requirements include those commitments made in the response to the BTP and the referenced SERs.

In RAI 2.3.3.7-2, the staff stated that the provision of fire detection and alarm systems and components is required by both BTP APCSB 9.5-1, Appendix A, and by 10 CFR 50 Appendix R. LRA Section 2.3.3.7 identifies heat and smoke detection installed in all areas containing safety-related equipment as being within the scope of license renewal, except as exempted by the NRC, although Table 2.2-3 of the LRA does not specifically list the fire detection and alarm system under Instrumentation and Controls. Based on these criteria, the staff requested that the applicant identify fire detection and alarm system as falling within the scope of license renewal and subject to an AMR or else provide a justification for its exclusion. In a letter dated May 22, 2002, the applicant responded that Table 2.2-1 of the LRA indicated that FPSs are included within the scope of license renewal and are discussed in Section 2.3.3.7. In LRA Section 2.3.3.7, page 2-66, the applicant states: "The term 'fire protection system' refers to the integrated complex of components and equipment provided for detection and suppression of fires." In Section 2.5, page 2-130, the applicant states that, other than station blackout, for all other electrical and I&C components, the passive, long-lived electrical components subject to an AMR were identified as commodities. Specifically, for the fire protection detection and alarm system, this would include insulated cables and connections (connectors, splices, and terminal blocks).

The staff reviewed the applicant's response and agrees that the fire detection and alarm system is included within the scope of license renewal and is included in the LRA as part of the fire protection system, even though those components are not explicitly identified in the electrical and I&C sections of the LRA. The staff further agrees that the passive, long-lived portions of the fire detection and alarm system are subject to an AMR for the electrical commodity groups, as addressed in Section 2.5.

In RAI 2.3.3.7-6, the staff requested that the applicant provide the basis for excluding components of the torus hardened vent from the scope of license renewal even though the containment venting intended function is cited for Appendix R post-fire safe shutdown for Fire Areas 1B (Unit 2), 6S (Unit 2 and Unit 3), 12B (Unit 3), 13S (Unit 3), and 39 (Unit 2 and Unit 3) at Peach Bottom. In a letter dated May 22, 2002, the applicant responded that systems analyzed to achieve compliance with Appendix R (and thereby 10 CFR 50.48) are described in FPP Section 5.2.2, and components are listed in FPP Table A-3. The torus hardened vent does not appear in either of these sections. Therefore, the torus hardened vent is not a system that falls within the scope of systems used to satisfy 10 CFR 50.48.

The staff reviewed the applicant's response to RAI 2.3.3.7-6. The staff agrees that the torus hardened vent is not listed as a safe shutdown component. This component is not part of a fire suppression strategy. Therefore, the staff concurs that the torus hardened vent is not within the scope of the LRA for 10 CFR 50.48 compliance.

In RAI 2.3.3.7-7, the staff requested that the applicant include carbon dioxide discharge nozzles and discharge piping in the scope of the license renewal or provide the technical justification for their exclusion, since they do not appear in LRA Table 2.3.3-7. In a letter dated May 22, 2002, the applicant responded that license renewal drawing LR-M-318, sheet 4, shows that the discharge piping and discharge nozzles for the carbon dioxide suppression system are within the scope of license renewal and that these components were included in an AMR in Table 2.3.3-7 for their specific environments.

The staff reviewed the applicant's response and agrees that carbon dioxide system discharge piping and nozzles are included within the scope of license renewal. Table 3.3-7 identifies piping, valves, and nozzles with a "dry gas" environment. Only the carbon dioxide tank is specifically mentioned as part of the low pressure CO_2 system. Based on the applicant's response, Table 3.3-7 also applies to the piping, valve, and nozzle components of the CO_2 system. The staff therefore finds the applicant's response to RAI 2.3.3.7-7 to be acceptable.

On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.3.3.7.3 Conclusion

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the fire protection SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.3.8 Control Room Ventilation System

2.3.3.8.1 Summary of Technical Information in the Application

In Section 2.3.3.8 of the LRA, the applicant identified the boundaries of the control room ventilation system (CRVS) and the components within the scope of license renewal and subject to an AMR. The applicant stated in Section 2.3.3.8 of the LRA that additional information for the CRVS is provided in Section 10.13 of the UFSAR for both Unit 2 and Unit 3. The system scoping for the CRVS is shown in license renewal drawing LR-M-384, sheets 1-3, all Rev. A.

The CRVS is a safety-related system that is common to PBAPS Units 2 and 3. The system consists of several subsystems: control room fresh air supply, control room emergency ventilation filter, control room air conditioning ventilation supply, and the control room return air system. The system ensures the habitability of the control room under the 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 environment.

The CRVS 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 filtration 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 HEPA filters upstream and downstream of the charcoal filter.

In Section 2.3.3.8 of the LRA, the applicant identified the following intended functions for the CRVS that relate to 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3):

- Control room isolation and filtration - The control room ventilation system provides isolation and filtration for the control room during accident conditions.

- Ventilation - The system provides ventilation for the control room during normal, abnormal, accident, and post-accident conditions.

The applicant described its process for identifying the SCs subject to an AMR in Section 2.1.2 of the LRA. Based on this methodology, the applicant identified the portions of the CRVS that are within the scope of license renewal in control room heating, ventilation, and air-conditioning (HVAC) evaluation boundary drawings LR-M-384, sheets 1, 2, and 3, Rev. A. On the basis of the system intended functions identified above, the applicant determined that the components of the CRVS designated as safety-related are within the scope of license renewal. Using the methodology described in Section 2.1.2 of the LRA, the applicant compiled a list of the SCs and component types within the license renewal boundaries and subject to an AMR and identified their intended functions. The applicant provided this list in Table 2.3.3-8 of the LRA.

The applicant identified the following component groups comprising component types that are within the scope of license renewal and subject to an AMR:

- casting and forging (valve bodies)
- elastomer (filter plenum access door seals, fan flex connections)
- piping (pipe, tubing)
- piping specialties (flow elements)
- sheet metal (ductwork, damper enclosures, plenums, fan enclosures, louvers)

Except for the louvers, which provide a throttle intended function, all of the remaining component types provide a pressure boundary intended function.

2.3.3.8.2 Staff Evaluation

The staff reviewed Section 2.3.3.8 of the LRA and Section 10.13 of the Peach Bottom UFSAR to determine whether there is reasonable assurance that the CRVS components and supporting structures within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

The staff reviewed the license renewal drawings LR-M-384, sheets 1-3, Rev. A, for the CRVS. The drawings show the evaluation boundaries for the portions of the CRVS within the scope of license renewal. The staff also reviewed LRA Table 2.3.3-8, which lists those SSCs that are subject to an AMR.

The staff also reviewed Section 10.13 of the UFSAR to determine if any portions of the CRVS met the scoping criteria in 10 CFR 54.4(a) were not identified as falling within the scope of license renewal. The staff also reviewed the UFSAR sections to determine if there were any system functions that were not identified as intended functions in the LRA, and to determine if there were SSCs that have intended functions that might have been omitted from the scope of SCs requiring an AMR. The staff also reviewed the above CRVS evaluation boundary drawings to determine if any SCs within the evaluation boundaries were omitted from the scope of SCs requiring an AMR under 10 CFR 54.4(a)(1). The staff compared the intended functions described in the UFSAR with those identified in the LRA. The staff then determined whether the applicant had properly identified the SCs subject to an AMR from among those identified as falling within the scope of license renewal.

The applicant identified and listed the SSCs subject to an AMR for the CRVS in Table 2.3.3-8 of the LRA, using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff sampled SCs from Table 2.3.3-8 to verify that the applicant adequately identified the SCs subject to an AMR. The staff also sampled the SCs within the scope of license renewal but not subject to an AMR to verify that these SCs performed their intended functions with moving parts or with a change in configuration or properties, and were subject to replacement based on a qualified life or specified time period.

By letter dated March 12, 2002, the staff requested additional information regarding those portions of the CRVS identified as not within the scope of license renewal to help ensure that they do not perform any intended functions that are within scope. The applicant submitted responses to those RAIs, as discussed below.

RAI 2.3.3.8-1 requested specific information concerning the areas that constitute the main control room envelope (MCRE) and perform intended functions such as cooling and filtration (in order to maintain control room habitability (CRH) and meet Appendix A to 10 CFR Part 50, General Design Criterion (GDC) 19).

In addition, the staff did not believe that the boundary for the MCRE had been adequately delineated and asked the applicant to verify that all CRVS components inside the MCRE (including housings of air handling units and fan coil units and their associated ductwork, housings of fire damper and control valves, the air intake, and housings of exhaust fans with purge ductwork), which are relied on to perform the safety-related cooling/ventilation intended functions are identified as falling within the scope of license renewal and subject to an AMR on license renewal drawing LR-M-384, Rev. A, and in Table 2.3.3.8 of the LRA.

In a letter dated May 22, 2002, the applicant responded that, as indicated in LRA Section 2.3.3.8, the intended functions of the CRVS are control room isolation, filtration, and ventilation. The components that are required to perform these intended functions are in-scope and identified on license renewal drawings LR-M-384 sheets 1, 2, and 3, Rev. A. All other SSCs and housings, except heating coils enclosures, that are subject to an AMR are identified in LRA. Heating coil enclosures were inadvertently omitted from the LRA table, which will be revised to include these coil enclosures. The staff also reviewed USFAR Section 10.13 “Main Control Room Air Condition, “ and verified the CRVS serves the main control room adjacent offices (control room enclosure); therefore, the staff finds the applicants response acceptable. The staff found the addition of the heating coil enclosures acceptable because they perform an intended pressure boundary function meeting the requirements of 10 CFR 54.21(a)(1).

In RAI 2.3.3.8-2, the staff stated that LRA Table 2.3.3-8 did not identify the components and their housings listed below, although these components, including their housings, support the intended function of the CRVS to comply with the requirements of the Appendix A to 10 CFR Part 50, GDC 19. These components are shown on license renewal drawing LR-M-384, sheet 1, as falling within the scope of license renewal but are not listed in Table 2.3.3-8 of the LRA. The staff requested that the applicant provide a justification for the exclusion of these components and their housings from an AMR.

Housings and components excluded are:

- reheat coil 00E072, drawing LR-M-384, sheet 3, location H2
- thermowell for temperature transmitter TT00174, drawing LR-M-384, sheet 3, location H2
- louver, drawing LR-M-384, sheet 1, location D8
- preheat coil 00E068, sheet 1, at location D7
- HEPA filters OAF041, drawing LR-M-384, sheet 1, location G6, and OBF041at location F6
- HEPA filters OAF050, drawing LR-M-384, sheet 1, location G5 and OBF050 at location F5

The staff indicated that if the filter media for the components identified above were excluded on the basis that these media components are routinely replaced (consumables), the applicant should describe the plant-specific monitoring program and the specific performance standards and criteria for periodic replacement.

In a response to RAI 2.3.3.8-2, the applicant stated that heating coil enclosures (reheat and preheat coils) were inadvertently omitted from the LRA tables. These components should be included in LRA Table 2.3.3-8 as having a pressure boundary function in a sheltered, ventilation atmosphere environment. The applicant further indicated that there is no thermowell for temperature transmitter TT00174. The temperature element is a capillary type and penetrates the ventilation duct through a bulkhead type fitting. The bulkhead fitting is considered as part of the ventilation ductwork hardware for license renewal. The louver shown on license renewal drawing LR-M-384, sheet 1, at location D8, is mounted in a wall opening at the ventilation intake and does not include any pressure boundary housing or enclosure. The applicant confirmed that heating coil enclosures are subject to an AMR and should be included in LRA Table 2.3.3-8. As stated above, the staff found the inclusion of the heating coil enclosures in Table 2.3.3-8 acceptable because they meet the requirements of 10 CFR 54.21(a)(1).

The filter media for the components identified above are short-lived and passive and are not subject to an AMR. Periodic testing and inspection programs include filter performance such that system intended functions are maintained. The filters are monitored during the annual filter train surveillance tests, including verification of acceptable maximum differential pressure. System filters are replaced as conditions warrant; therefore an AMR is not required. The staff considers the applicant's response to RAI 2.3.3.8-2 partially acceptable. However, the filter housings of the HEPA filters were excluded from the LRA Table 2.3.2-8 and the applicant failed to provide justification for this exclusion in its response. The applicant needs to include these housings in LRA Table 2.3.2-8 to indicate that they are subject to an AMR or justify their exclusion from an AMR. This was Open Item 2.3.3.8.2-1.

In a letter dated November 26, 2002, the applicant provided clarifying information concerning the filter housings of the HEPA filters. In response to the Open Item, the applicant stated that the HEPA filters shown on drawing LR-M-384 sheet 1 are installed and fully enclosed inside filter plenum (filter housing). The filter plenum is included in the scope of license renewal and subject to an AMR, and is identified in the LRA Table 2.3.3-8 as a sheet metal plenum, and the NRC staff agrees with the applicant's clarification for the filter housings of the HEPA filters. Therefore, Open Item 2.3.3.8.2-1, is closed.

In RAI 2.3.3.8-3. the staff indicated that LRA Table 2.3.3-8 did not identify test connections shown on license renewal drawing LR-M-384, sheet 1, Rev. A, at locations D1 (three locations), F1(three locations), F5 (three locations), F6 (two locations), G2 (one location), G4 (two locations), D2 (one location), D3 (one location), D5 (three locations), and D6 (three locations). The staff requested that the applicant provide justification for the exclusion of these test connections from Table 2.3.3-8 of the LRA as not subject to an AMR.

In response to RAI 2.3.3.8-3, the applicant stated that the test connections are included in the scope of license renewal and are subject to an AMR. The test connections are considered as part of the ventilation ductwork hardware for license renewal. The staff considers the applicant's response to RAI 2.3.3.8-3 to be acceptable.

In RAI 2.3.3.8-4, the staff requested that the applicant clarify whether sealant materials at PBAPS Units 2 and 3, used to maintain the MCRE at positive pressure with respect to the adjacent areas in order to prevent the unfiltered in-leakages inside MCRE, are included in the scope of license renewal and subject to an AMR, and if so, provide the relevant information to complete Table 2.3.3.8 of the LRA. If the sealants are not considered subject to an AMR, the applicant was asked to provide justification for their exclusion. The applicant responded that sealant materials are included as a commodity item in LRA Section 2.4.14, in Table 2.4-14. The staff considers the applicant's response to be acceptable.

In RAI 2.3.3.8-5, the staff identified that GDC 19 of Appendix A to 10 CFR Part 50 requires cooling and protection against radiation and toxic gas release in order to achieve and maintain MCRE habitability during and after an accident. The staff requested the applicant to clarify whether the following main control room (MCR) cooling system components and their associated housings fall within the scope of license renewal and are subject to an AMR because they provide a safety-related cooling function:

Drawing LR-M-384, sheet 2:

- supply fans, OAV028 at location F6 and OABV028 at location C5
- cooling coils, OAE069 at location F5 and OBEV069 at location C5
- supply roll filter, OOF038 at location E3
- bag filter, OOF057 at location E4
- preheat coil, OOE110 at location F2
- louver at location F1
- ductwork, dampers, and instrumentation tubing and valves

Drawing LR-M-384, sheet 3

- return air fans, OAV027 at location C7 and OBV029 at location A7
- closed cooling control room ventilation, fan, OOV326 at location C4
- filter, OOF327 at location C3
- control room ventilation reheat coil, OOE072 at location H2
- balance dampers at locations F7 and G7
- control room toilet exhaust fan, OOV033 at location G8
- ductwork, dampers, and instrumentation tubing and valves

If the components and the associated housings identified above were excluded from the scope of license renewal and not subject to an AMR, the applicant was asked to provide justification for their exclusion.

The applicant responded that, as indicated on license renewal drawing legend LR-M-300, license renewal drawing note 1, with the exception of the reheat coil 00E072, none of the above-identified components are highlighted on the license renewal drawing and none fall within the scope of license renewal. The components identified in this RAI are not required to support the system intended functions of control room isolation, filtration, and ventilation and are therefore not within the scope of license renewal. The reheat coil 00E072 is addressed in the response to RAI 2.3.3.8-2, above.

The staff considers the applicant's response to RAI 2.3.3.8-5 incomplete because the system's safety-related radiation, cooling, and toxic protection functions are required to meet Appendix A to 10 CFR Part 50, GDC 19. LRA Section 2.3.3.8 refers to UFSAR Section 10.13, which states that the control room ventilation subsystem (of CRVS) provides ventilation for the control room under normal and accident conditions. Also, the UFSAR subsection 10.13.4 states that the emergency cooling and ventilation system for the control room and other safety-related equipment rooms are installed in seismic Class I structure and are provided with 100% redundancy. Therefore, the staff finds that the control room air conditioning ventilation subsystem provides a safety-related cooling function to meet the requirements of GDC 19. Therefore, the applicant needs to include the CRVS subsystem components (that support the accident function to maintain control room habitability) listed below within the scope of license renewal and subject to an AMR (in LRA Tables 2.3.3-8 and 3.3-8) in accordance with 10 CFR 54.4 and 10 CFR 54.21 (a)(1) or justify their exclusion:

<u>LRA Drawing LR-M-384, Sheet 2</u>
- Housings for supply fans (OAV028/OBVO28),
- Cooling coils (OAE069/OBE069)
- Ductwork and damper housings

<u>LRA Drawing LR-M-384, Sheet 3</u>
- Housings for two balance dampers at F7 and G7
- Housings for return air fans (OAV029/OBV020)
- Ductwork and damper housings

Additionally, if the filter media and filter housings for the supply roll filter and bag filter (OOF038/OOF057, as shown in LRA Drawing LR-M-384, Sheet 2) were excluded on the basis that these media components are routinely replaced (i.e., they are consumables) the applicant should describe the plant specific monitoring program and the specific performance standards and criteria for periodic replacement. This was Open Item 2.3.3.8.2-2.

In a letter dated November 26, 2002, the applicant stated in response to Open Item 2.3.3.8.2-2 that the CRVS consists of (1) the safety-related control room fresh air supply subsystem, and (2) the control room emergency ventilation filter subsystem. The CRVS also consists of (1) the non-safety-related control room air conditioning ventilation supply subsystem, (2) the control room return air subsystem, and (3) the control room toilet exhaust subsystem. The safety-related control room fresh air supply subsystem and the control room emergency ventilation filter subsystems are the only CRVS subsystems relied upon to assure control room habitability, and therefore, are within the scope of the license renewal and subject to an AMR.

The non-safety-related subsystems including the control room air conditioning ventilation supply subsystem of the CRVS are not required for control room habitability and do not have any safety-related intended functions. Therefore, these associated components are not within the scope of license renewal and are not subject to an AMR and the plant specific monitoring program including periodic replacement criteria for the media components (roll filter and bag filter (OOF038/OOF057)) are not warranted.

The NRC staff agrees with the applicant's above clarification as to why certain non-safety-related subsystems which are not relied upon to assure control room habitability are not within the scope of license renewal. Because the applicant has included the safety-related portions of the CRVS that are relied on to support accident conditions (i.e., control room habitability) within the scope of license renewal and subject to an aging management review, Open Item 2.3.3.8.2-2 is closed.

2.3.3.8.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the control room ventilation SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.3.9 Battery and Emergency Switchgear Ventilation System

2.3.3.9.1 Summary of Technical Information in the Application

In Section 2.3.3.9 of the LRA, the applicant identified portions of the battery and emergency switchgear ventilation system (BESVS) and the components that fall within the scope of license renewal and are subject to an AMR. The applicant stated in Section 2.3.3.9 of the LRA that additional information for the BESVS is provided in Section 10.14 of the UFSAR for both Units 2 and 3. The system scoping for the BESVS is shown in license renewal drawings LR-M-389, sheet 1, Rev. A, and LR-M-399, sheets 1 and 4, both Rev. A.

The BESVS consists of a common air supply system and separate exhaust systems. Outdoor air is filtered and 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 exhausts air to atmosphere at the radwaste building roof or back to the suction of the supply fan as controlled by an air-operated damper. One of the two battery room exhaust fans discharges exhausts air from the battery rooms to atmosphere at the radwaste building roof exhaust stack. Loss of duct pressure automatically starts standby fans and sounds an alarm in the MCR.

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. The BESVS is described in additional detail in UFSAR Section 10.14. License renewal drawings referenced for the BESVS are LR-M-389 and LR-M-399, both Rev. A.

Intended Functions within the Scope of License Renewal:

In Section 2.3.3.9 of the LRA, the applicant identified the following intended functions for the BESVS that relate to 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3):

- Ventilation - The system provides ventilation to the emergency switchgear and battery rooms during normal and abnormal accident conditions

- Heating - The system provides room heating during all normal plant operating conditions and following a design basis event or accident conditions. Heating is the recirculation of heated air with reduced air exchange with the outdoor environment

On the basis of the functions identified above, the applicant determined that all BESVS safety-related components (electrical, mechanical, and instrument) are within the scope of license renewal. The applicant described its process for identifying the SCs subject to an AMR in Section 2.1.2 of the LRA. Based on this methodology, the applicant identified the portions of the BESVS that fall within the scope of license renewal in BESVS evaluation boundary drawings LR-M-389, sheet 1 for Common Only, and LR-M-399, sheet 1 for Common Only, and sheet 4, for Unit 2, 3, and Common, all Rev. A. Using the methodology described in Section 2.1.2 of the LRA, the applicant compiled a list of the SCs and component types within the license renewal system boundaries and subject to an AMR and identified their intended functions. The applicant provided this list in Table 2.3.3-9 of the LRA.

The applicant identified the following device types that are identified as within the scope of license renewal and subject to an AMR:

- casting and forging (valve bodies)
- elastomer (fan flex connections)
- piping (tubing)
- sheet metal (ductwork, plenums, damper enclosures, fan enclosures, louvers exhaust hoods, bird screens)

Except for the bird screens, which have a filter intended function, and the louvers, which have a throttle intended function, all of the remaining device types provide a pressure boundary intended function.

2.3.3.9.2 Staff Evaluation

The staff reviewed Section 2.3.3.9 of the LRA and UFSAR Section 10.14 to determine whether there is reasonable assurance that the battery and emergency switchgear ventilation system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

The staff reviewed the BESVS evaluation boundary drawings LR-M-389, sheet 1, Rev. A, and LR-M-399, sheets 1 and 4, both Rev. A, of the LRA. The drawings show the evaluation boundaries for the portions of the BESVS within the scope of license renewal. The staff also reviewed LRA Table 2.3.3-9, which lists those SSCs subject to an AMR.

The staff also reviewed the above BESVS evaluation boundary drawings to determine if any SSCs within the evaluation boundaries were omitted from the scope of SSCs requiring an AMR under 10 CFR 54.4(a)(1). The staff compared the functions described in the UFSAR with those identified in the LRA. The staff then determined whether the applicant had adequately identified the SSCs subject to an AMR from among those identified as falling within the scope of license renewal.

The applicant identified and listed the SSCs subject to an AMR for the BESVS in Table 2.3.3-9 of the LRA, using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff sampled SCs from LRA Table 2.3.3-9 to verify that the applicant did identify the SSCs subject to an AMR. The staff also sampled the SSCs within the scope of license renewal but not subject to an AMR to verify that these SSCs performed their intended functions with moving parts or with a change in configuration or properties, and were subject to replacement based on a qualified life or specified time period.

After completing the initial review, by letter dated March 12, 2002, the staff requested specific information concerning the exclusion of certain SSCs from the scope of license renewal and/or an AMR, and the applicant submitted responses to those RAIs, as discussed below.

In RAI 2.3.3.9-1, the staff noted that LRA Table 2.3.3-9 does not list the heating coils and their housings 0AE073 and 0BE073 as being subject to an AMR, although these components are shown at locations F5 and C5 on license renewal drawing LR-M-399, sheet 1, as being within the scope of license renewal. The staff believes that these components provide a passive boundary function for the BESVS. Accordingly, the staff requested the applicant to provide its justification for the exclusion of the above components from Table 2.3.3-9 of the LRA. In a letter dated May 22, 2002, the applicant responded that the subject heating coils are steam heating coils that are installed inside the fan unit (0AV034, 0BV034) enclosure housing, and do not provide a passive boundary function for the BESVS. However, the fan enclosures (housings) are included in LRA Table 2.3.3-9.

The staff considers failure of a steam heating coil pressure boundary to cause steam leakage into the BESVS ventilation duct, thereby degrading HVAC unit performance. The staff believes that these heating coils do fall within the scope of license renewal and are subject to an AMR. This was Open Item 2.3.3.9.2-1.

In a letter dated November 26, 2002, the applicant provided additional clarifying information stating that the steam heating coils (0AE073, 0BE073) have been included in the scope of license renewal and are subject to an AMR. They are listed in the Auxiliary Steam System as a heat exchanger (ventilation heaters) component, which has been added to the scope of license renewal as indicated in response to RAIs 2.1.2-3, 2.1.2-4, and 3.3-1 which were transmitted by letter dated May 21, 2002 (see page 25 of 28); therefore, Open Item 2.3.3.9.2-1, is closed.

In RAI 2.3.3.9-2, the staff identified that the system description for the BESVS in LRA Section 2.3.3.9 stated that one of the two battery room exhaust fans discharges air from the battery rooms at the radwaste building roof exhaust stack. However, license renewal drawing LR-M-399, sheet 4, Rev. A, at location G4, shows that the exhaust from the battery room fans is discharged from the MCR roof. If the exhaust air from the battery room exits from the radwaste building roof as stated, then the radwaste exhaust vent must be identified on license renewal drawing LR-M-399, sheet 4, Rev. A, at location B3, as falling within the scope of license renewal and subject to an AMR. The staff requested the applicant to clarify the above discrepancy.

In a letter dated May 22, 2002, the applicant responded that the radwaste exhaust vent and the ductwork leading to it are within the scope of license renewal and are subject to an AMR. These components (ductwork and exhaust hoods) are included in LRA Table 2.3.3-9. License renewal drawing LR-M-399, sheet 4, Rev. A, is in error, and will be revised to identify the exhaust vent and associated ductwork as in-scope. The staff considers the applicant's response to be acceptable.

As stated in applicant's response to RAI 2.2-1.1(b) (refer to SER Section 2.2.3), the instrument air system piping, tubing, and valve bodies that are required to support the safety-related pneumatic system pressure boundary were realigned from the instrument air system to the BESVS for license renewal. The normal source for compressed gas to the pneumatic controls is from the non-safety-related instrument air system. However, portions of the pneumatic controls in the BESVS are safety-related, as are the nitrogen bottles, which are the safety-related source for compressed gas to the pneumatic controls. The subject piping and tubing with associated valves is shown as cross-hatched (pneumatic piping and tubing symbol) and is highlighted as falling within the scope of license renewal on boundary drawings LR-M-399 sheets 1 and 4, Rev. A.

As discussed above, portions of the instrument air system were realigned to the BESVS. In a letter dated October 30, 2001, the staff identified certain components that were omitted from Tables 2.3.3-9 and the corresponding table in Section 3.3. In a November 16, 2001, response, applicant stated that when LRA Table 2.3.3-9 was prepared, the BESVS component groups in the gas environment AMR were inadvertently omitted. Additionally, the applicant stated that LRA Table 2.3.3-9 requires the addition of "dry gas" in the "Environment" column for both the "valve bodies" and "pipe" entries. The applicant further explained that the valve bodies are brass material, and the pipe is copper material. In its May 22, 2002, response to the staff's March 12, 2002, RAIs 2.2-1.1(a) and (b), the applicant clarified which systems or portions thereof were realigned, and revised LRA Table 3.3-9. The revision adds pipe to the component group of piping which performs the intended function of pressure boundary. The staff finds the addition of the components in the dry gas environment to be acceptable because they perform an intended function, as described in 10 CFR 54.21(a)(1), without moving parts or without a change in configuration or properties.

On the basis of the above review the staff did not find any other omissions by the applicant of SSCs within the scope of license renewal.

2.3.3.9.3 Conclusions

On the basis of its review the staff concludes there is reasonable assurance that the applicant has adequately identified the battery and emergency switchgear ventilation SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.3.10 Diesel Generator Building Ventilation System

2.3.3.10.1 Summary of Technical Information in the Application

In Section 2.3.3.10 of the LRA, the applicant identified the boundaries of the diesel generator building ventilation system (DGBVS) and the DGBVS components within the scope of license renewal and subject to an AMR. Section 2.3.3.10 of the LRA stated that additional information for the DGBVS is provided in Section 10.14 of the UFSAR for PBAPS Units 2 and 3. The components of the DGBVS in the scope of license renewal are shown in license renewal drawing LR-M-392, sheet 1, Rev. A.

The DGBVS provides heating, cooling, and ventilation for personnel comfort, for the diesel generators and associated equipment, and for the emergency service water (ESW) booster pumps. The system provides ventilation and cooling to the emergency diesel generator (EDG) 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 EDG 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.

In Section 2.3.3.10 of the LRA, the applicant identified the following intended functions for the DGBVS that relate to 10 CFR 54.4(a):

- Ventilation - The system provides ventilation to maintain an acceptable environment to support proper diesel generator operation during normal plant operating conditions and following design basis events.

- Cooling - The system provides cooling to maintain an acceptable environment to support proper operation of the diesel generators and their associated equipment during normal plant operating conditions and following design basis events.

On the basis of the functions identified above, the applicant determined that all DGBVS safety-related components fall within the scope of license renewal. The applicant described its process for identifying the SCs subject to an AMR in Section 2.1.2 of the LRA. Based on this methodology, the applicant identified the portions of the DGBVS that fall within the scope of license renewal in DGBVS evaluation boundary drawings LR-M-392, sheet 1, Rev. A. Using the methodology described in Section 2.1.2 of the LRA, the applicant compiled a list of the SCs and component types within the license renewal system boundaries and subject to an AMR and identified their intended functions. The applicant provided this list in Table 2.3.3-10 of the LRA.

The applicant identified the following device types that are identified as falling within the scope of license renewal and subject to an AMR:

- elastomer (fan flex connections)
- sheet metal (ductwork, damper enclosures, fan enclosures, louvers)

Except for the louvers, which have a throttle intended function, the remaining components have a pressure boundary intended function.

2.3.3.10.2 Staff Evaluation

The staff reviewed Section 2.3.3.10 of the LRA and Section 10.14 of the UFSAR to determine whether there is reasonable assurance that the diesel generator building ventilation system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

The staff also reviewed the above DGBVS evaluation boundary drawings to determine if any SSCs within the evaluation boundaries were omitted from the scope of SCs requiring an AMR under 10 CFR 54.4(a)(1). The staff compared the functions described in the UFSAR with those identified in the LRA. The staff then determined whether the applicant had properly identified the SSCs subject to an AMR from among those identified as falling within the scope of license renewal.

The applicant identified and listed the SSCs subject to an AMR for the DGBVS in Table 2.3.3-10 of the LRA, using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff sampled SSCs from Table 2.3.3-10 to verify that the applicant did identify the SSCs subject to an AMR. The staff also sampled SSCs within the scope of license renewal but not subject to an AMR to verify that these SSCs performed their intended functions with moving parts or with a change in configuration or properties, and were subject to replacement based on a qualified life or specified time period.

By letter dated March 12, 2002, after completing the initial review, the staff requested additional information regarding the DGBVS and the applicant submitted responses to those RAIs, as discussed below.

In RAI 2.3.3.10-1, the staff identified that LRA Table 2.3.3-10 did not list the housings of the unit heaters identified in drawings OAE097 at location F5, OBE097 at location F4, OCE097 at location E5, ODE097 at location E4, OEE097 at location E5, OFE097 at location E4, OGE097 at location D5, OHE097 at location D4, OAE140 at location G5, and OBE140 at location F5.

If the components and their associated housings identified above were excluded from the scope of license renewal and not subject to an AMR, the staff asked the applicant to provide justification for their exclusion.

In a letter dated May 22, 2002, the applicant responded that the identified unit heaters are not in the scope of license renewal. These components are not identified as in-scope on license renewal drawing LR-M-392. As indicated in LRA Section 2.3.3.10, the system intended functions are ventilation and cooling. Heating is not an intended function of the DGBVS. These unit heaters are not safety-related and do not have any intended functions for license renewal. The staff considers the applicant's response to be acceptable, as the plant's current licensing basis (CLB) requires DGBVS heating to be available during normal operation only.

On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.3.3.10.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the diesel generator building ventilation SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.3.11 Pump Structure Ventilation System

2.3.3.11.1 Summary of Technical Information in the Application

In Section 2.3.3.11 of the LRA, the applicant identified the portions of the pump structure ventilation system (PSVS) and the components falling within the scope of license renewal and subject to an AMR. Section 2.3.3.10 of the LRA stated that additional information for the PSVS is provided in Section 10.14 of the PBAPS UFSAR for Units 2 and 3. The components that are within the scope of license renewal for the PSVS are shown in license renewal drawing LR-M-392, sheet 1, Rev. A.

The ESW and high-pressure service water (HPSW) compartment houses the ESW pumps, HPSW pumps, fire pumps, and service water screen wash pumps. The ventilation is provided with a supply and exhaust system in each of the two seismic Class I compartments. The PSVS 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 air plenum.

In Section 2.3.3.11 of the LRA, the applicant identified the following intended functions for the PSVS that relate to 10 CFR 54.4(a):

- Ventilation - The system provides ventilation to maintain an acceptable environment to support proper ESW and HPSW pump operation during normal plant operating conditions and following design basis events.

- Cooling - The system provides cooling to maintain an acceptable environment to support proper operation of the ESW and HPSW pumps and their associated equipment during normal plant operating conditions and following design basis events.

On the basis of the functions identified above, the applicant determined that all PSVS safety-related components (electrical, mechanical, and instrument) fall within the scope of license renewal. The applicant described its process for identifying the SSCs subject to an AMR in Section 2.1.2 of the LRA. Based on this methodology, the applicant identified the portions of the PSVS that fall within the scope of license renewal in PSVS evaluation boundary drawings LR-M-392, sheet 1, Rev. A. Using the methodology described in Section 2.1.2 of the LRA, the applicant compiled a list of the SSCs and component types within the scope of license renewal and subject to an AMR and identified their intended functions. The applicant provided this list in Table 2.3.3-11 of the LRA.

The applicant identified the following component groups comprising component types that are identified as falling within the scope of license renewal and subject to an AMR:

- casting and forging (valve bodies)
- elastomer (flex hose connections)
- piping (tubing)
- sheet metal (ductwork, damper enclosures, fan enclosures, louvers, bird screens)

Except for the louvers, which have a throttle intended function, and the bird screens, which have a filter intended function, the remaining component types have a pressure boundary intended function.

2.3.3.11.2 Staff Evaluation

The staff reviewed Section 2.3.3.11 of the LRA and Section 10.14 of the PBAPS Units 2 and 3 UFSAR to determine whether there is reasonable assurance that the pump structure ventilation system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

The staff reviewed the PSVS license renewal drawings identified above. These drawings show the evaluation boundaries for the portions of the PSVS falling within the scope of license renewal. The staff compared the highlighted portions of these drawings which indicate the components identified as within the scope of license renewal to the components listed in LRA Table 2.3.3-11, which lists those components that are both within the scope of license renewal and subject to an AMR.

The staff also reviewed the above PSVS evaluation boundary drawings to determine if any SSCs within the evaluation boundaries were omitted from the scope of SSCs requiring an AMR under 10 CFR 54.4(a)(1). The staff compared the functions described in the UFSAR with those identified in the LRA. The staff then determined whether the applicant had properly identified the SSCs subject to an AMR from among those identified as falling within the scope of license renewal.

The applicant identified and listed the SSCs subject to an AMR for the PSVS in Table 2.3.3-11 of the LRA, using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff sampled SSCs from Table 2.3.3-11 to verify that the applicant did identify all SSCs subject to an AMR. The staff also sampled SSCs within the scope of license renewal but not subject to an AMR to verify that these SSCs performed their intended functions with moving parts or with a change in configuration or properties, or were subject to replacement based on a qualified life or specified time period.

By letter dated March 12, 2002, the staff requested specific information concerning the exclusion of the certain components from the scope of license renewal and/or an AMR and the applicant responded to the RAIs as discussed below.

In RAI 2.3.3.11-1, the staff stated that LRA Section 2.3.3.11, page 2-76, identified both ESW pumps and HPSW pumps as being ventilated and cooled by the PSVS. Similarly, UFSAR Section 10.14.3.3, page 10.14-2, Rev. 17, 04/2000, describes the ESW/HPSW compartment as housing the HPSW pumps, ESW pumps, fire pumps, and service water screen wash pumps.

The staff further identified that license renewal drawing LR-M-392, sheet 1, Rev. A, at locations C4 and C5, shows four pump structure compartments identified as falling within the scope of license renewal. Two of these compartments are labeled “Emergency, Water Pumps” for Units 2 and 3. Each compartment is shown as containing two intake and two exhaust fans, plus a unit heater. The staff asked the applicant to clarify whether these are the compartments described in the LRA and the UFSAR as housing the HPSW pumps, ESW pumps, fire pumps, and service water screen wash pumps. The other two compartments are identified as “Circulating Water Pumps.” The staff also requested that the applicant identify all of the components contained in these four compartments that fall within the scope of license renewal and confirm whether they are cooled by PSVS.

In a letter dated May 22, 2002, the applicant replied that license renewal drawing LR-M-392, sheet 1, Rev. A, provides a schematic representation of the pump structure for the purposes of identifying the ventilation system flow paths. The compartment identified as “Emergency. Water Pump” on license renewal drawing LR-M-392, sheet 1, is the same compartment as described in UFSAR Section 10.14.3.3. As stated in the LRA and the UFSAR, the PSVS cools this compartment containing all of the subject pumps. As described in LRA Section 2.3.3.11, each compartment includes two supply fans, two exhaust fans, and one unit heater. The two compartments identified as “Circ. Water Pumps” are within the scope of license renewal for structural considerations, but do not contain any components within the scope of license renewal that require ventilation or cooling. The staff considers the applicant's response to be acceptable.

In RAI 2.3.3.11-2, the staff identified that LRA Table 2.3.3-11 did not list the housings of the unit heaters shown on the license renewal drawing LR-M-392, sheet 1, Rev. A , one at location C3, two at location C4, two at location C5, and one at location C6. Also LRA Table 2.3.3-11 did not list housings of roof exhausters shown on license renewal drawing LR-M-392, sheet 1, Rev. A, 0AV062 at location D6, 0BV062 at location D5, 0CV062 at location D5, 0DV062 at location D3, 0EV062 at location D3, and 0FV062 at location D4. The staff requested justification for their exclusion.

The applicant responded in a letter dated May 22, 2002, that, as indicated on the license renewal drawing LR-M-300, sheet 1, Rev. A, the unit heaters are not identified as falling within the scope of license renewal on license renewal drawing LR-M-392, sheet 1. The intended functions of the PSVS are ventilation and cooling. The system does not have an intended function for room heating, so the unit heaters are not required to support the system intended function. The unit heaters are not in the scope of license renewal and not subject to an AMR.

The roof exhausters are not identified as falling within the scope of license renewal on license renewal drawing LR-M-392, sheet 1, Rev. A. The roof exhausters are associated with the circulating water pump rooms. The circulating water pump rooms do not contain any safety-related pumps. Cooling or ventilation of the circulating water pump rooms is not an intended function of the PSVS. The circulating water pump room roof exhausters are not safety-related and are not required to support any intended functions. The roof exhausters do not fall within the scope of license renewal and are not subject to an AMR. In view of the fact that the subject components do not have a safety-related intended function in the plant’s CLB, the staff considers the applicant's response to be acceptable.

On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.3.3.11.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the pump structure ventilation SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.3.12 Safety-Grade Instrument Gas System

2.3.3.12.1 Summary of Technical Information in the Application

In Section 2.3.3.12 of the LRA, the applicant described the components of the safety-grade instrument gas (SGIG) system that fall within the scope of license renewal and are subject to an AMR. The Peach Bottom UFSAR Table of Contents does not list the SGIG system, but it is described in the sections discussing the containment atmosphere dilution (CAD) system

(UFSAR Section 5.2.3.9) and the instrument air, service air, and instrument nitrogen systems (UFSAR Section 10.17).

The primary purpose of the SGIG system is to provide a safety-grade, pneumatic (nitrogen) supply to support short-term and long-term operation of safety equipment. The SGIG system supplies pressurized nitrogen gas from the containment atmospheric dilution tank as a backup to normal instrument air. The safety-grade pneumatic supply is isolated from the non-safety-grade portion of the air supply by spring-loaded, soft-seat, check valves designed for zero leakage. Following a LOCA coincident with a loss of instrument air, the SGIG system supplies pressurized nitrogen gas as a backup pneumatic source to the containment atmospheric control system purge and vent isolation valves, the torus-to-secondary-containment vacuum breakers, and the containment atmospheric dilution vent control valves.

Description of Realigned Components:

Piping and valves associated with the instrument nitrogen system supply to main steam relief valves RV-71E, H and J, shown on drawing LR-M-333, sheets 1 and 3, have been realigned into the SGIG system for the purpose of license renewal. These main steam relief valves are credited during certain Appendix R fire scenarios and are within the scope of license renewal. The instrument nitrogen system piping and valves connected to these main steam relief valves were realigned to the SGIG system because they form part of the pressure boundary necessary to support the SGIG system's intended function of providing a safety-related backup nitrogen supply.

Piping and valves associated with the instrument air system supply to air-operated valves in the containment atmospheric control and dilution system have been realigned into the SGIG for the purpose of license renewal. The instrument air system piping and valves described above are shown on drawings LR-M-367 and LR-M-372 and were realigned to the SGIG system because they form part of the pressure boundary necessary to support the SGIG system's intended function of providing a safety-related back-up nitrogen supply.

Intended Functions within the Scope of License Renewal:

In Section 2.3.3.12 of the LRA, the applicant identified the following intended function for the SGIG system, as defined in 10 CFR 54.4:

- Backup nitrogen supply - The safety-grade instrument gas system provides a backup nitrogen supply to safety-related pneumatically operated components.

Using the methodology described in LRA Section 2.1.2, as specified in 10 CFR 54.21(a)(1), the applicant listed the mechanical component groups subject to an AMR and identified their intended functions in Table 2.3.3-12 of the LRA. The applicant identified the following component groups:

- casting and forging (valve bodies)
- piping (pipe)
- piping specialties (flexible hoses)

The intended function for the SGIG system components subject to an AMR is pressure boundary integrity.

2.3.3.12.2 Staff Evaluation

The staff reviewed Section 2.3.3.12 of the LRA and UFSAR Sections 5.2.3.9 and 10.17 to determine whether there is reasonable assurance that the safety-grade instrument gas system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

In the Section 2.3.3.12 of the LRA, the applicant listed two license renewal boundary diagrams, LR-M-367 and LR-M-372, for the SGIG system. The boundary diagrams were highlighted to identify those portions of the system that were within the scope of license renewal in accordance with 10 CFR 54.4. The staff compared the boundary diagrams to the system description in the UFSAR to ensure that they were representative of the SGIG system. The staff also sampled portions of the license renewal boundary diagrams that were not highlighted to ensure these components did not perform any of the functions as defined in 10 CFR 54.4.

The applicant identified the components subject to an AMR for the SGIG system and their intended functions in Table 2.3.3-12 of the LRA using the screening methodology described in Section 2.1.3 of the LRA. The staff evaluated the applicant's scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff subsequently performed a review of the implementation of the methodology for the SGIG system by sampling the components identified as falling within the scope of license renewal but not subject to an AMR to verify that these components performed the intended functions with moving parts or with a change in configuration or properties, or are subject to replacement base on a qualified life or specified time period.

After completing its initial review, by letters dated January 23, 2002, and March 12, 2002, the staff requested additional information regarding the SGIG system, and the applicant submitted responses to those RAIs on February 28, 2002, and May 22, 2002, as discussed below.

The staff issued RAI 2.1.2-2 to document discussions with the applicant concerning the realignment of interfacing system components which took place during an audit of the applicant's scoping and screening methodology. The portion of the applicant's response to RAI 2.1.2-2 which concerns the SGIG system is the fourth case of interfacing system component realignment considered, which covers components that are shared between systems that are within the scope of license renewal and systems that are not within scope. In its response, the applicant explains that though it normally considers interfacing components as belonging to the out-of-scope, non-safety-related system, for the purpose of identifying intended functions for license renewal, it is necessary to realign these interfacing components to in-scope systems for which they perform a pressure boundary function.

Based upon the applicant's response to RAI 2.1.2-2, the staff issued RAI 2.2-1.1(b) to request that the applicant identify, in an unambiguous and traceable manner, the interfacing components belonging to non-safety-related, out-of-scope systems which it had realigned into the SGIG system. The applicant responded to RAI 2.2-1.1(b) by stating that the non-safety-related instrument nitrogen and instrument air systems interface with the SGIG system at components where the normal pneumatic supply is from the instrument nitrogen or instrument air system and the safety-related backup pneumatic supply is from the SGIG system. These interfacing components belonging to the instrument air and nitrogen systems are required to support the SGIG system pressure boundary intended function, and the applicant realigned them to the SGIG system for the purpose of license renewal. The applicant's response to RAI 2.2-1.1(b) then identified the specific components that were realigned (which the staff has previously discussed in Section 2.3.3.12.1 of this SER), and indicated that these components had been included in LRA Table 2.3.3-12. The staff's review of Table 2.3.3-12 confirmed that the components realigned to the SGIG system from the out-of-scope instrument air and nitrogen systems were included in the list of SGIG system components subject to an AMR. Based upon its review of the applicant's responses to RAI 2.1.2-2 and RAI 2.2-1.1(b), the staff concludes that the applicant has adequately identified the components belonging to out-of-scope systems which it has realigned into the SGIG system.

Peach Bottom UFSAR Section 10.17.5 (page 10.17-5) states: "The containment atmosphere dilution system purge and vent valves are supplied with separate safety-grade pneumatic supplies to the inflatable seals to maintain their leak-tight condition." Additionally, the Peach Bottom UFSAR states that one of the suppression chamber-to-secondary containment vacuum breaker air-operated valves (one on each unit) is supplied with an inflatable valve seal. However, on drawing LR-M-367 (locations A-7 and E-2), the inflatable valve seals are not shown to be within the scope of license renewal. In RAI 2.3.3.12-1, the staff asked the applicant to clarify whether the valve seals are within the scope of license renewal. In a letter dated May 22, 2002, the applicant stated that the inflatable valve seals are part of the valve internals whose function is to prevent flow through the valve. The applicant further stated that, as such, the inflatable seals do not perform a pressure boundary function for license renewal that is subject to an AMR, in accordance with NUREG-1800, Table 2.1.5, Item 111. Consistent with NUREG-1800, the NRC staff finds the applicant's response to be acceptable because the inflatable seals change configuration and properties to perform their intended function. Therefore, in accordance with 10 CFR 54.21(a)(1)(i), the staff concludes that the inflatable seals are not considered passive components, and are not subject to an AMR.

On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.3.3.12.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the safety-grade instrument gas SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.3.13 Backup Instrument Nitrogen to ADS

2.3.3.13.1 Summary of Technical Information in the Application

In Section 2.3.3.13 of the LRA, the applicant described the components of the backup instrument nitrogen to the automatic depressurization system (ADS) within the scope of license renewal and subject to an AMR. License renewal drawings, LR-M-333 and LR-M-351, both Rev. A, were also provided for the backup instrument nitrogen to ADS. This system is further described in Sections 4.4 and 10.17 of the Peach Bottom UFSAR.

The backup instrument nitrogen to ADS 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 ground-level. The split ring header supplies five ADS valves, three from one section of the header, and two from the other section.

The backup instrument nitrogen to ADS provides a safety-related pneumatic supply of nitrogen to the ADS valves in the event that the instrument nitrogen system is unavailable or inoperable. Short-term ADS operation is provided by locally mounted accumulators on each ADS valve which supply sufficient pneumatic pressure for two valve actuations at 70% of drywell design pressure. The backup instrument nitrogen to ADS also supports the 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 post-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 in fire areas that have been postulated to render the ADS valves available only for 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.

Description of Realigned Components:

The instrument nitrogen system accumulators associated with the main steam ADS relief valves were realigned from the instrument nitrogen system to the backup instrument nitrogen to ADS. The instrument nitrogen system piping, valves, and flexible hoses that are part of the ADS valve nitrogen accumulator safety-related pressure boundary were realigned from the instrument nitrogen system to the backup instrument nitrogen to ADS. Flow elements of the instrument nitrogen system that are part of the backup instrument nitrogen supply to ADS pressure boundary were realigned from the instrument nitrogen system to the backup instrument nitrogen to ADS.

Intended Functions Within the Scope of License Renewal:

The applicant described its methodology for identifying the mechanical components within the scope of license renewal in Section 2.1.2 of the LRA. The applicant stated that since the backup instrument nitrogen to ADS supplies a long-term, backup, safety-grade supply of nitrogen to the five ADS valves during all normal plant operating and accident conditions, it falls within the scope of license renewal. The intended function for the backup instrument nitrogen to ADS components subject to an AMR is pressure boundary integrity.

Using the methodology described in LRA Section 2.1.2, as specified in 10 CFR 54.21(a)(1), the applicant listed the mechanical component groups subject to an AMR and identified their intended functions in Table 2.3.3-13 of the LRA. The applicant identified the following component groups:

- casting and forging (valve bodies)
- piping (pipe)
- piping specialties (flexible hoses and flow elements)
- vessel (accumulators)

2.3.3.13.2 Staff Evaluation

The staff reviewed Section 2.3.3.13 of the LRA and UFSAR Sections 4.4 and 10.17 to determine whether there is reasonable assurance that the backup instrument nitrogen to ADS components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

The applicant highlighted portions of the license renewal drawings, LR-M-333 and LR-M-351, to identify those components that it considered to be within the scope of license renewal. The staff compared the boundary diagrams to the system description in the UFSAR to ensure that they were representative of the backup instrument nitrogen to ADS. The staff also sampled portions of the boundary diagrams that were not highlighted to ensure these components did not perform any of the functions defined in 10 CFR 54.4.

The applicant identified the components subject to an AMR and their intended functions for the backup instrument nitrogen to ADS in Table 2.3.3-13 of the LRA using the screening methodology described in Section 2.1.3 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff subsequently performed a review of the implementation of the methodology for the backup instrument nitrogen to ADS by sampling the components identified as falling within the scope of license renewal but not subject to an AMR to verify that these components performed the intended functions with moving parts or with a change in configuration or properties, or are subject to replacement base on a qualified life or specified time period.

After completing its initial review, by letters dated January 23, 2002, and March 12, 2002, the staff requested additional information regarding the backup instrument nitrogen to ADS, and the applicant submitted responses to those RAIs on February 28, 2002, and May 22, 2002, as discussed below.

The staff issued RAI 2.1.2-2 to document discussions with the applicant concerning the realignment of interfacing system components which took place during an audit of the applicant's scoping and screening methodology. The portion of the applicant's response to RAI 2.1.2-2 which concerns the backup instrument nitrogen to ADS is the fourth case of interfacing system component realignment considered, which covers components that are shared between systems that are within the scope of license renewal and systems that are not within scope. The applicant's response explains that, though it normally considers interfacing components as belonging to the out-of-scope non-safety-related system, for the purpose of identifying intended functions for license renewal, it is necessary to realign these interfacing components to in-scope systems for which they perform a pressure boundary function.

Based upon the applicant's response to RAI 2.1.2-2, the staff issued RAI 2.2-1.1(a) to request that the applicant provide a traceable method for identifying the interfacing components belonging to non-safety-related out-of-scope systems which the applicant had realigned into systems considered within the scope of license renewal. In response to RAI 2.2-1.1(a), the applicant stated that interfacing components belonging to the instrument nitrogen system performed an intended pressure boundary function for the backup instrument nitrogen to ADS. The applicant then identified the specific components that were realigned (which the staff has previously discussed in Section 2.3.3.13.1 of this SER), and indicated that these components had been included in LRA Table 2.3.3-13. The staff's review of Table 2.3.3-13 confirmed that the components realigned to the backup instrument nitrogen to ADS from the out-of-scope instrument nitrogen system were included in the list of backup instrument nitrogen to ADS components subject to an AMR. Based upon its review of the applicant's responses to RAI 2.1.2-2 and RAI 2.2-1.1(a), the staff found that there is reasonable assurance that the applicant has adequately identified the components belonging to out-of-scope systems which it has realigned to the boundary of the backup instrument nitrogen to ADS.

On license renewal boundary drawing LR-M-333, sheets 1 and 2, piping components such as weld caps (location A3), reducers, and increasers (various locations) were shown to be within the scope of license renewal. However, these piping components were not specifically listed in Table 2.3.3-13 as requiring an AMR. In RAI 2.3.3.13-1, the staff asked the applicant to clarify whether these components are included within the "pipe" component group. In a letter dated May 22, 2002, the applicant confirmed that these components are pipe fittings and are included in the "pipe" component group listed in LRA Table 2.3.3-13. The staff finds the applicant's response to be acceptable because it indicates that these piping components will be subject to an AMR in accordance with 10 CFR 54.21(a)(1).

Section 2.3.3.13 of the LRA states that the backup nitrogen supply to ADS consists of a split ring header with a seismic Category 1 bottle rack. The bottle rack is not mentioned in Sections 4.4 and 10.17 of the Peach Bottom UFSAR, nor is it shown on drawings LR-M-333 and LR-M-351. Additionally, the bottle rack is not listed in Table 2.3.3-13 as requiring an AMR. In RAI 2.3.3.13-2, the staff questioned whether the bottle rack is subject to an AMR. In a letter dated May 22, 2002, the applicant stated the subject bottle racks are included in the component support group as discussed in Section 2.4.13 of the LRA. The staff reviewed Section 2.4.13 of the LRA, confirming that bottle racks are included in the support member component group, and that this component group is included in Table 2.4-13 as being subject to an AMR. Therefore, in accordance with 10 CFR 54.21(a)(1), the staff finds the applicant's response to be acceptable.

Section 4.4 of the Peach Bottom UFSAR states: “Containment isolation is provided for safety-grade pneumatic supply lines into containment by use of check valves and other automatic valves outside containment.” However, in Table 2.3.3-13 of the LRA, containment isolation is not listed as an intended component function. In RAI 2.3.3.13-3, the staff asked the applicant to clarify whether this function should be included in the table. In a letter dated May 22, 2002, the applicant clarified that, as described in Table 2.1-1, the intended pressure boundary function for mechanical components includes providing containment isolation for fission product retention. The staff agrees that the component-level pressure boundary function provides for and includes containment isolation and fission product retention. Therefore, the staff concludes that there is reasonable assurance that the applicant has adequately identified the intended functions of the components in Table 2.3.3-13, and finds the applicant’s response to be acceptable.

On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.3.3.13.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the backup instrument nitrogen to ADS SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.3.14 Emergency Cooling Water System

2.3.3.14.1 Summary of Technical Information in the Application

In Section 2.3.3.14 of the LRA, the applicant identifies the emergency cooling water (ECW) system component groups falling within the scope of license renewal and subject to an AMR. This system is further described in Section 10.24 of the Peach Bottom UFSAR.

The ECW system (in conjunction with the ESW and HPSW systems) is designed to remove the 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, Conowingo Pond. The ECW system consists of 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. 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 ECW pump, in conjunction with the ESW booster pump and HPSW pumps, supplies cooling water to heat exchangers required to bring Units 2 and 3 to safe shutdown. Return water from the ESW system flows through one of the two ESW booster pumps and is pumped into the emergency cooling tower.

Section 2.3.3.14 of the LRA identifies the following intended functions for the ECW system that relate to 10 CFR 54.4(a):

- Component cooling - The ECW system (including the emergency cooling tower) provides cooling water flow to transfer heat from the ESW and HPSW systems during the mitigation of a flood or loss of the normal heat sink, Conowingo Pond.

- Back-up cooling - The ECW system is available to provide a reliable back-up source of cooling water to the ESW system during normal plant operation in the unlikely event of failure of the ESW pumps.

Using the methodology described in LRA Section 2.1.2, the applicant compiled a list of the mechanical component groups subject to an AMR and identified their intended functions in Table 2.3.3-14 of the LRA. Table 2.3.3-14 identifies the following component groups and component types as falling within the scope of license renewal and subject to an AMR:

- casting and forging (valve bodies, pump casings)
- piping (pipe, tubing)
- piping specialties (flow elements)

All ECW components identified above have a pressure boundary intended function.

2.3.3.14.2 Staff Evaluation

The staff reviewed Section 2.3.3.14 of the LRA and UFSAR Section 10.24 to determine whether there is reasonable assurance that the emergency cooling water system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

The staff reviewed those portions of the ECW system that were not identified as being within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4. The staff also reviewed the UFSAR to determine if there were any additional system functions that were not identified in the LRA, and verified that those additional functions did not meet the scoping requirements of 10 CFR 54.4.

The staff then determined whether the applicant had properly identified the SSCs that are subject to an AMR from among those portions of the ECW system that are identified as being within scope of license renewal. The applicant identifies and lists the SSCs subject to AMR for the ECW system in Table 2.3.3-14 of the LRA using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff performed its review by sampling the SSCs that the applicant determined to be within the scope of license renewal but not subject to AMR to verify that these SSCs performed its intended function with moving parts or with a change in configuration or properties or were subject to replacement base on a qualified life or specified time period.

The applicant identified the portions of the ECW system that are within-scope of license renewal in the drawings referenced in the LRA. The detailed flow diagrams were highlighted to identify those portions of the system that are within the scope of license renewal. The applicant highlighted those components which it believes perform at least one of the scoping requirements of 10 CFR 54.4. The staff compared the LRA flow diagrams to the system drawings and the descriptions in the UFSAR to ensure they were representative of the ECW system. The staff sampled portions of the flow diagram that were not highlighted to verify that these components did not meet any the scoping criteria in 10 CFR 54.4.

By letter dated March 12, 2002, the staff requested the below additional information regarding the ECW system. The applicant responded in a letter dated May 22, 2002, as described below.

In RAI 2.3.3.14-1, the staff asked about the fittings, strainers, flanges, increasers, and reducers that were shown as falling within the scope of license renewal on drawing LR-M-330, sheet 1, but were not listed in Table 2.3.3-14 of the LRA. The applicant responded that the reducers, increasers, fittings, and flanges are part of the piping component group, which includes piping, tubing, and fittings included in LRA Table 2.3.3-14. The applicant also stated that the strainer was a temporary startup strainer that is no longer installed. Based on the above, the staff found the applicant's response to RAI 2.3.3.14-1 acceptable.

In RAI 2.3.3.14-2, the staff requested that the applicant clarify the status of the discharge pond, which is shown as falling within the scope of license renewal on drawing LR-M-330, sheet 1, at location A7-A8. However, the discharge pond is not shown as falling within the scope of license renewal on site plan LR-S-001 or in LRA Table 2.2-2. The applicant responded that the discharge pond does not perform any license renewal intended functions. The boundary drawing will be revised to remove the highlighting from drawing LR-M-330, sheet 1. The structural site plan is the correct drawing to use for the discharge pond and it indicates that the discharge pond is not within the scope of license renewal. The staff agrees with the applicant that the ECW system provides a safety-related ultimate heat sink intended function that does not require operability of the discharge pond. Therefore the staff finds the applicant's response concerning the status of the discharge pond to be acceptable.

On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.3.3.14.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the emergency cooling water SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.3.15 Condensate Storage System

2.3.3.15.1 Summary of Technical Information in the Application

In Section 2.3.3.15 of the LRA, the applicant identifies the condensate storage system component groups falling within the scope of license renewal and subject to an AMR. This system is further described in Sections 4.7 and 6.4 of the Peach Bottom UFSAR.

The applicant classified the condensate storage system as non-safety-related. It is included within the scope of license renewal for its 10 CFR 54.4(a)(2) support role as the water supply for the HPCI and RCIC systems during fire safe shutdown and station blackout scenarios. During normal operation, the condensate storage system provides plant system makeup needs, receives reject flow, and provides condensate for any continuous service needs. It is also the preferred water supply for the HPCI system and the RCIC system; however, in the event that the condensate storage tank is unavailable, these systems automatically switch to the torus, which is the safety-grade water source for these systems. The condensate storage system consists of two 200,000-gallon-capacity carbon steel condensate storage tanks, (one for each unit) two condensate transfer pumps, a condensate transfer system keep-full pump, and associated piping and valves necessary to complete required system functions. The condensate storage system is common to Peach Bottom Units 2 and 3.

In Section 2.3.3.15 of the LRA, the applicant identifies the following intended function for the condensate storage system that relates to 10 CFR 54.4(a):

- Water storage and supply - The condensate storage system supports HPCI and RCIC systems during fire safe shutdown and station blackout events by providing a water supply and a means for its storage.

Using the methodology described in LRA Section 2.1.2, the applicant compiled a list of the mechanical component groups subject to an AMR and identified their intended functions in Table 2.3.3-15 of the LRA. Table 2.3.3-15 identifies the following component groups and component types as falling within the scope of license renewal and subject to an AMR:

- casting and forging (valve bodies)
- piping (pipe, tubing)
- vessels (condensate storage tanks, tank nozzles)

All of the condensate storage system components identified above have a pressure boundary intended function.

2.3.3.15.2 Staff Evaluation

The staff reviewed Section 2.3.3.15 of the LRA and UFSAR Sections 4.7 and 6.4 to determine whether there is reasonable assurance that the condensate storage system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

The staff reviewed the text and diagrams submitted by the applicant in Section 2.3.3.15 of the LRA and the Peach Bottom UFSAR to determine if the applicant adequately identified the SSCs of the condensate storage system that are in the scope of license renewal. The staff verified that those portions of the condensate storage system that meet the scoping requirements of 10

CFR 54.4 are included within the scope of license renewal and are identified as such by the applicant in Section 2.3.3.15 of the LRA. The staff then focused its review on those portions of the condensate storage system that were not identified as being within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4. The staff also reviewed the UFSAR to determine if there were any additional system functions that were not identified in the LRA, and verified that those additional functions did not meet the scoping requirements of 10 CFR 54.4.

The staff then determined whether the applicant had properly identified the SSCs that are subject to an AMR from among those portions of the condensate storage system that are identified as being within-scope of license renewal. The applicant identifies and lists the SSCs subject to AMR for the condensate storage system in Table 2.3.3-15 of the LRA using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff performed its review by sampling the SSCs that the applicant determined to be within the scope of license renewal but not subject to AMR to verify that these SSCs performed its intended function with moving parts or with a change in configuration or properties or were subject to replacement base on a qualified life or specified time period.

The applicant identified the portions of the condensate storage system that are within-scope of license renewal in the drawings referenced in the LRA. The detailed flow diagrams were highlighted to identify those portions of the system that are within the scope of license renewal. The applicant highlighted those components which it believes perform at least one of the scoping requirements of 10 CFR 54.4. The staff compared the LRA flow diagrams to the system drawings and the descriptions in the UFSAR to ensure they were representative of the condensate storage system. The staff sampled portions of the flow diagram that were not highlighted to verify that these components did not meet any of the scoping criteria in 10 CFR 54.4.

By letter dated March 12, 2002, the staff requested additional information regarding the condensate storage system. The applicant responded to the RAIs in a letter dated May 22, 2002, as discussed below.

RAI 2.3.3.15-1 concerned the safety-related function of the condensate storage system to provide a backup source of water to the control rod drive system. As stated in UFSAR Section 3.4.5, “In the event that the flow from the condensate system is interrupted at any time, the condensate storage tank provides a backup source to ensure CRDS operability without operator action being required.” The applicant was asked to provide the basis for the exclusion of this intended function from Section 2.3.3.15 of the LRA.

In RAI 2.3.3.15-2, the staff requested that the applicant provide the basis for considering the pipes that connect to the condensate storage tank at a low elevation on P&ID drawing LR-M-309 and the freeze protection piping (from the auxiliary heating/steam supply system) as not falling with the scope of license renewal. This RAI was a follow-up to RAI 2.3.3.15-1 contending that the condensate storage system performs a safety-related function.

In response to both RAIs, the applicant stated that the function of the condensate storage tank to provide a backup source to the control rod drive system is a function that supports normal control rod drive system operation and is not a safety-related function. Only the control rod scram function and the alternate rod insertion functions are safety-related intended functions of the control rod drive system in the Peach Bottom CLB. Neither of these intended functions requires operability of the control rod drive system water pumps, and therefore neither requires a suction source for the pumps. The scram accumulator stores sufficient energy to fully insert a control rod independent of any other source of energy. The accumulator consists of a water volume pressurized by nitrogen. The accumulator has a piston separating the water on top from the nitrogen below. A check valve in the charging line to each accumulator prevents the loss of water in the event supply pressure is lost. The scram accumulator provides the required energy to rapidly insert the control rod for both the control rod scram intended function and the alternate rod insertion intended function. The control rod drive system water pumps are not required to perform these safety-related intended functions. Therefore, the condensate storage system does not have a safety-related CLB intended function.

The staff reviewed the applicant's response concerning the intended function of the condensate storage tank. The staff agrees with the applicant that its function as a backup water source to the control rod drive system is not relied on to shut down the reactor and maintain it in a safe shutdown condition. As a result, this function does not meet the requirements of 10 CFR 54.21(a)(1). Therefore, the staff finds the applicant's responses to RAIs 2.3.3.15-1 and 2.3.3.15-2 to be acceptable.

On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.3.3.15.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the condensate storage SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.3.16 Emergency Diesel Generator (EDG)

2.3.3.16.1 Summary of Technical Information in the Application

In the LRA, the applicant describes the components of the emergency diesel generators (EDGs) for the Peach Bottom Atomic Power Station, Units 2 and 3, that are within the scope of license renewal and subject to an aging management review (AMR). The EDGs are further described in Section 8.5 of the Peach Bottom UFSAR. The staff reviewed the EDGs to determine whether there is reasonable assurance that the applicant has identified and listed the mechanical components within the scope of license renewal and subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

The applicant described its methodology for identifying the mechanical components within the scope of license renewal in Section 2.1.2 of the LRA. The applicant lists, in Table 2.2-1, the mechanical systems within the scope of license renewal that satisfy the criteria in 10 CFR Part 54.4. The EDGs, as a system, were included within the scope of license renewal since the following intended functions meet the criteria in 10 CFR Part 54.4:

- Provide emergency AC power - The EDG sets provide Class 1E electrical power to the emergency buses in a loss of offsite power (LOOP) or a LOCA coincident with a LOOP.

- Support offsite power transfer - The EDG sets are used to support the transfer of power from one offsite safeguard source to another by providing a parallel source of AC power to the emergency buses during the transfer operation.

The applicant also lists mechanical systems not within the scope of license renewal in Table 2.2-1. Based on the scoping methodology, the applicant, in Section 2.3.3.16 and Table 2.3.3-16 of the LRA, describes the EDGs and EDG components that are within the scope of license renewal and subject to an AMR.

Four EDGs supply independent standby AC power to Peach Bottom Units 2 and 3. Each EDG set consists of a diesel engine, a generator, and auxiliary systems (starting air, fuel oil, jacket cooling, air coolant, and lubricating oil). Each EDG is connected to one 4kV Class 1E emergency bus per unit. The EDGs are connected to the 4kV emergency buses upon a loss of offsite power after generator voltage and frequency are established. The 4kV emergency switchgear bus distributes AC power to engineered safeguard and selected nonsafeguard systems. Power provided to engineered safeguard loads is divided into four safeguard channels, “A” through “D,” for each unit so that the failure of one diesel generator or one 4kV emergency bus will not prevent a safe shutdown of either unit.

The applicant identified EDG mechanical components that require an AMR in Table 2.3.3-16 in the LRA. This table lists the types of component groups, including their component types, with their passive function and environment identified. The applicant identified the following 6 component groups and 23 component types as subject to an AMR:

- casting and forging (valve bodies, pump casings, strainer bodies, strainer screens)
- elastomer (flexible hoses)
- heat exchanger (jacket coolant coolers, air coolant coolers, lube oil coolers),
- piping (pipe, tubing, fittings)
- piping specialties (thermowells, thermowell caps, thermocouple caps, expansion joints, restricting orifices, drain taps)
- vessel (fuel oil storage tank, fuel oil day tanks, expansion tanks, lube oil tanks, air receivers, silencers)

All of the EDG components identified above, except for the strainer screens, have a pressure boundary intended function. Strainer screens have a filter intended function. The jacket coolant coolers, air coolant coolers, and lube oil coolers also have a heat transfer intended function.

2.3.3.16.2 Staff Evaluation

The staff reviewed Section 2.3.3.16 of the LRA and Section 8.5 of the Peach Bottom UFSAR to determine whether there is reasonable assurance that the emergency diesel generator system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

The staff reviewed the mechanical components in Table 2.3.3-16 for PBAPS Units 2 and 3 to determine whether any other components associated with the EDG meet the scoping criteria of 10 CFR 54.4(a), but were not included within the scope of license renewal. The staff then reviewed portions of the UFSAR descriptions to ensure that all mechanical components of the EDG had been adequately identified and that they were passive, long-lived and performed their intended functions without moving parts or with a change in configuration or change in properties and were not subject to replacement based on a qualified life or specified time period. In Section 2.3.3.16 of the LRA, the applicant listed one license renewal drawing, LR-M-377, Rev. A, for the EDG, which the staff reviewed. The license renewal drawing was highlighted to identify those portions of the system included within the scope of license renewal. The applicant highlighted those components that perform an intended function meeting the requirements 10 CFR 54.21(a)(1). The staff then compared the boundary diagram to the system description in the UFSAR to ensure that the diagram was representative of the EDG. The staff also sampled portions of the license renewal drawings that were not highlighted to ensure these components did not perform any intended functions that meet the criteria of 10 CFR 54.4(a).

The staff identified several EDG components on license renewal boundary drawing LR-M-377 that were within the scope of license renewal but not subject to an AMR. The staff believes that components such as the EDG lube oil standby heater casing and spare weld caps perform an intended function, as described in §54.4, without moving parts or without a change in configuration or properties, and should be subject to an AMR.

In a letter to the applicant dated March 12, 2002, the staff requested additional information relating to the EDG components shown on engineering drawing LR-M-377 as being within the scope of license renewal but not subject to an AMR. The applicant responded to the staff's question in a letter to the NRC dated May 22, 2002. As a result, the applicant provided its supplement to Table 2.3.3-16, adding the casings of the lube oil standby heater and jacket coolant standby water heater as being subject to an AMR. The casings that are being added under the EDGs in Table 2.3.3-16 perform an intended function of pressure boundary. The staff found the addition of the casings to be acceptable because they perform their intended functions without moving parts or without a change in configuration or change in properties, meeting the requirements in 10 CFR 54.21(a)(1). The applicant also clarified that the spare weld caps in question are considered pipe fittings and, as such, are included in the piping component group in Table 2.3.3-16.

The applicant, in the RAI response, stated that components such as the turbo charger, filter housing, scavenging air blower, and crank case are part of the diesel generator which performs an active function such, they are not subject to an AMR. The staff reevaluated the boundaries for the diesel generator identified on drawing LR-M-377 to ensure the components of concern were in fact part of the diesel. The staff found the applicant's exclusion of these components from an AMR acceptable, as the components in question are included within the boundary of the complex assembly and complex assemblies are not subject to an AMR in accordance with NUREG-1800.

The NRC staff reviewed the LRA, supporting information in the UFSAR, and the applicant's response to the staff's RAI. In addition, the staff sampled several components from Table 2.3.3-16 and LR-M-377 to determine whether the applicant properly identified the components that are within the scope of license renewal and subject to an AMR. On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.3.3.16.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the emergency diesel generators SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.3.17 Suppression Pool Temperature Monitoring System

2.3.3.17.1 Summary of Technical Information in the Application

In Section 2.3.3.17 of the LRA, the applicant identifies the components of the suppression pool temperature monitoring system (SPOTMOS) falling within the scope of license renewal and subject to an AMR. This system is further described in Section 7.20.4.7 of the Peach Bottom UFSAR.

The SPOTMOS provides indication of the individual and average bulk torus water temperature in the control room, the remote shutdown panel, and the HPCI alternative control station to ensure torus water is maintained within specified temperature limits. The SPOTMOS has two independent divisionalized monitoring systems, consisting of temperature sensors and a processing unit to display temperatures. For each division, only one of the dual elements for each sensor is permanently connected. The remaining elements are provided as installed spares. The SPOTMOS is normally energized and is supplied from independent divisions of Class 1E power sources.

In Section 2.3.3.17 of the LRA, the applicant identifies the following intended function for the SPOTMOS that relates to 10 CFR 54.4(a):

- Torus water temperature monitoring - The suppression pool temperature monitoring system provides indication of the individual and average bulk torus water temperature in the control room to ensure torus water is maintained within specified temperature limits.

Using the methodology described in LRA Section 2.1.2, the applicant compiled a list of the mechanical component groups subject to an AMR and identified their intended functions in Table 2.3.3-17 of the LRA. Table 2.3.3-17 identifies the following component group and component type as falling within the scope of license renewal and subject to an AMR:

- penetration sleeves (thermowells)

The SPOTMOS component identified above has a pressure boundary and fission product barrier intended function.

2.3.3.17.2 Staff Evaluation

The staff reviewed Section 2.3.3.17 of the LRA and UFSAR Section 7.20.4.7 to determine whether there is reasonable assurance that the suppression pool temperature monitoring system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

The staff reviewed the text and diagrams submitted by the applicant in Section 2.3.3.17 of the LRA and the Peach Bottom UFSAR to determine if the applicant adequately identified the SSCs of the SPOTMOS that are in the scope of license renewal. The staff verified that those portions of the SPOTMOS that meet the scoping requirements of 10 CFR 54.4 are included within the scope of license renewal and are identified as such by the applicant in Section 2.3.3.17 of the LRA. The staff then focused its review on those portions of the SPOTMOS that were not identified as being within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4. The staff also reviewed the UFSAR to determine if there were any additional system functions that were not identified in the LRA, and verified that those additional functions did not meet the scoping requirements of 10 CFR 54.4.

The staff then determined whether the applicant had properly identified the SSCs that are subject to an AMR from among those portions of the SPOTMOS that are identified as being within-scope of license renewal. The applicant identifies and lists the SSCs subject to AMR for the SPOTMOS in Table 2.3.3-17 of the LRA using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff performed its review by sampling the SSCs that the applicant determined to be within the scope of license renewal but not subject to AMR to verify that these SSCs performed its intended function with moving parts or with a change in configuration or properties or were subject to replacement based on a qualified life or specified time period.

The applicant identified the portions of the SPOTMOS that are within-scope of license renewal in the drawings referenced in the LRA. The detailed flow diagrams were highlighted to identify those portions of the system that are within the scope of license renewal. The applicant highlighted those components which it believes perform at least one of the scoping requirements of 10 CFR 54.4. The staff compared the LRA flow diagrams to the system drawings and the descriptions in the UFSAR to ensure the diagrams were representative of the SPOTMOS. The staff sampled portions of the flow diagram that were not highlighted to verify that these components did not meet any the scoping criteria in 10 CFR 54.4.

By letter dated March 12, 2002, the staff requested additional information by asking the applicant to provide a correct drawing reference that identifies the components of this system.

In a response dated May 22, 2002, the applicant stated that LR-M-361 was the correct license renewal reference drawing for the SPOTMOS. The majority of the components in this system are active and are not subject to an AMR. As indicated in LRA Table 2.3.3-17, the only components subject to an AMR are the penetration sleeves (or thermowells) in the torus shell. The SPOTMOS thermowells are associated with temperature elements 2-71A1, B1, C1, D1, E1, F1, G1, H1, J1, K1, L1, M1, and N1 and 2-71A2, B2, C2, D2, E2, F2, G2, H2, J2, K2, L2, M2, and N2 are shown on drawings LR-M-361, sheet 1, zone C-3; sheet 2, zone D-7; sheet 3, zone C-3; and sheet 4, zone D-7. However, these temperature elements were inadvertently shown as out-of-scope on the referenced license renewal boundary drawing. The applicant further stated that these temperature elements will be identified as in-scope on the license renewal boundary drawings for identification of the associated thermowells that are subject to an AMR. The suppression pool temperature monitoring system will be added to the list of included license renewal systems in drawing Note 1, with a system flag of ST.

The staff agrees that the applicant’s response properly identifies the SPOTMOS components that are passive and long-lived, and that the proposed corrective actions address, in part, the records retention requirements of 10 CFR 54.37. Based on the above, the staff finds the applicant’s response to RAI 2.3.3.17 to be acceptable.

On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.3.3.17.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the suppression pool temperature monitoring SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.3.18 Cranes and Hoists

2.3.3.18.1 Summary of Technical Information in the Application

In Section 2.3.3.18, “Cranes and Hoists,” of the LRA, the applicant describes the structural components of the cranes and hoists system that are within the scope of license renewal and subject to an AMR. Cranes and hoists are further described in Section 10.3, 10.4, 12.2, 14.4, and Appendix C, of the Peach Bottom UFSAR. The staff reviewed the cranes and hoists to determine whether there is reasonable assurance that the applicant has identified and listed structures and components subject to AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

In Section 2.1 of the LRA, the applicant described its process for identifying the structural/civil components within the scope of license renewal and subject to an AMR. Based on its methodology, the applicant, in Table 2.2-1, identifies the cranes and hoists within the scope of license renewal and describes the results of its scoping methodology in Section 2.3.3.18 in the LRA.

As stated in the Peach Bottom UFSAR Section 10.4.10, "Reactor Building Crane," the reactor building cranes are designed such that no credible postulated failure of any crane component will result in the dropping of the fuel cask, there by, mitigating the consequences of a cask drop accident. In addition, the applicant describes its heavy load compliance program in UFSAR Section 10.4.11. The applicant's program incorporates a defense-in-depth philosophy to manage the handling of heavy loads on site such that no credible load drop will endanger the public safety and health. The applicant has excluded cranes and hoists from the scope of license renewal that do not have the potential to impact irradiated fuel, the reactor vessel, or safe shutdown equipment. In addition, Appendix C, "Structural Design Criteria," identifies seismic Class I structures and equipment as those whose failure could increase the severity of the design basis accident and cause release of radioactivity in excess of 10 CFR Part 100 limits, and those essential for safe shutdown and removal of decay heat following a loss-of-coolant accident (LOCA). The reactor building and circulating water pump structure cranes are identified in Appendix C as seismic Class I equipment. The applicant's scoping methodology captures cranes and hoists within the scope of license renewal that meet the intent of 10 CFR 54.4(a) because they perform the following system-level intended functions:

- Prevent fuel cask drop accident - The reactor building crane is designed to lift and transport a spent fuel cask so that no credible postulated failure of any crane component will result in the dropping of the cask.

- Heavy loads - The reactor building cranes support single-failure-proof criteria for lifting heavy loads over fuel in the reactor pressure vessel or over the spent fuel pool.

- Structural integrity - Cranes and hoists are required to maintain their structural integrity while they travel above or in proximity of safety-related SSCs.

On the basis of the above-described methodology, the applicant identified both the SSCs and the component groups that are part of the load handling cranes and hoists. Table 2.3.3-18 lists the following component groups and structural components that are subject to an AMR:

- circulating water pump structure crane, 35-ton gantry (structural members, rails, rail clips, and rail bolts)
- reactor building overhead bridge cranes (rails, rail clips, and rail bolts)
- other cranes and hoists (rails, monorail flanges, rail clips, and rail bolts)

SSCs of the component groups listed in Table 2.3.3-18 perform the intended functions of structural support, and structural support to non-safety-related components. As stated by the applicant, cranes and hoists within the proximity of safety-related SSCs are within the scope of license renewal. Load handling cranes and hoists in proximity of SSCs are designed and analyzed to perform tasks so as not to prevent safety-related SSCs from performing their intended functions. As a result, SSCs of cranes and hoists within the scope of license renewal perform their intended functions without moving parts or without change in configuration or properties, and are not subject to periodic replacement based on a qualified life or specified time limit.

2.3.3.18.2 Staff Evaluation

The staff reviewed Section 2.3.3.18 in the LRA and Peach Bottom UFSAR Sections 10.3, 10.4, 12.2, and 14.4, and UFSAR Appendix C to determine whether there is reasonable assurance that the cranes and hoists system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

The staff reviewed the structural component groups in Table 2.3.3-18 (i.e., structural members, rails, rail clips, monorail flanges, and rail bolts) to determine whether any other crane and hoist components meet the scoping criteria of 10 CFR Part 54.4(a), were not included within the scope of license renewal. The staff also examined the component groupings listed in Table 2.3.3-18 in the LRA to determine whether they are the only groups subject to an AMR in accordance with 10 CFR 54.21(a)(1).

In a letter dated March 12, 2002, the staff requested additional information from the applicant concerning the crane and hoist SSCs were subject to an AMR that are listed on Table 2.3.3-18 of the LRA. In RAI 2.3.3.18-1, the staff stated that the term “other cranes and hoists” was very general and not amenable to a review. Further, asked the applicant to provide a list of all cranes and hoists that are within the scope of license renewal and identify those subject to an AMR.

In a letter dated May 22, 2002, in response to RAI 2.3.3.18-1, the applicant identified the following list of cranes and hoists within the scope of license renewal pursuant to 10 CFR Part 54.4(a), and subject to an AMR:

- reactor building overhead bridge cranes
- turbine hall cranes
- emergency diesel generator bridge cranes
- circulating water pump structure crane, 35-ton gantry
- emergency cooling tower hoist
- service pole caddy platform overhead hoist
- equipment access airlock monorail and hoists
- southwest torus hatch hoist
- leveling tray hoists
- personnel airlock hoists
- precoat material handling hoist (Unit 2)
- fuel channel handling hoists
- CRD cask hoists
- CRD jib cranes
- recirculation pump motor hoists
- recirculation pump motor-generator-set hoists
- main steam line relief valve removal hoists

- turbine building west side vertical restraint rigging hoist
- turbine building east side vertical restraint rigging hoist
- 1-ton crane over storage area

The staff reviewed the list of cranes and hoists provided by the applicant and determined that they are within the scope of license renewal because they are included within the applicant's heavy load program and/or meet the seismic Class I equipment criteria of Appendix C of the UFSAR. As such, SSCs of the listed cranes and hoists perform the intended functions of providing structural support, and structural support to non-safety-related components within the scope of the rule. On the basis of this review, the staff found the applicant's response to the RAI acceptable.

In RAI 2.3.3.18-2, the staff asked the applicant to identify whether the following components are subject to an AMR:

- columns
- baseplates and anchors for attachment to structures
- structural crane components such as bridge girders, columns, trolley rails, baseplates, and anchors for attachment to structures

The staff also asked the applicant to provide the relevant information about the components to complete LRA Table 2.3.3-18. If a component is not subject to an AMR, the applicant was asked to provide a justification for its exclusion.

In response to RAI 2.3.3.18-2, the applicant stated that the components identified by the staff are within the scope of license renewal and subject to an AMR. However, not all of the components are part of the cranes and hoists and thus not all are not listed in Table 2.3.3-18 of the LRA. Structural crane components such as bridge girders, trolley, trolley rails, crane rails, clips, and bolts are included in the component group listed in Table 2.3.3-18. Crane girders, columns, beams, base plates, and anchors are a part of the building structural steel and included in the structural steel component group listed in LRA Table 3.5-1, 3.5-2, 3.5-4, 3.5-5, 3.5-10, or 3.5-11. The applicant identified that the content of Table 2.3.3-18 is consistent with NUREG-1801, Section VII B, and the table on page VII B-3.

The staff reviewed LRA Tables 3.5-1, 3.5-2, 3.5-4, 3.5-5, 3.5-10, and 3.5-11. In addition, the staff reviewed the Generic Aging Lessons Learned (GALL) Report, Section VII, Table VII B-3, to verify if the SSCs listed by the applicant in Table 2.3.3-18 as within scope are consistent with the GALL Report. On the basis of this review, the staff determined that the SSCs and their AMR results were included in the component groups in the tables identified by the applicant. However, the staff could not determine from the applicant's response how the SSCs in RAI 2.3.3.18-2 were captured within the scope of license renewal. 10 CFR 54.21 requires an applicant to identify and list those structures and components subject to an aging management review. The Section 3.0 tables only provide structural steel as a SC requiring an AMR. Therefore, the staff needs to understand how the structural steel component group is linked to Section 2.3.3.18 and how the scoping and screening results of Section 2 supports the applicant's position that components such as crane girders, columns, beams, base plates, and anchors are part of the building structural steel and subject to an AMR. Therefore, this issue was characterized as SER Open Item 2.3.3.18.2-1.

The staff and the applicant held a telephone conference on October 15, 2002, to discuss various SER open items which included the scoping and screening of cranes and hoists. During the conference, the applicant stated that the supporting structures of the cranes and hoist were included within the structural steel component group of Tables 2.4-1, 2.4-2, 2.4-4, 2.4-10, and 2.4-11. A review of the application during the conference provided inadequate justification for considering crane girders, columns, beams, base plates, and anchors as part of the structural steel component groups of the various Section 2.0 tables. To facilitate the staff review and to draw a link between Table 2.3.3-18 and the SCs of concern, the applicant agreed to revise Table 2.3.3-18 to list those components subject to an AMR in accordance with 10 CFR 54.21 and revise the above Section 2.0 tables to have the structural steel component group include the crane supporting SCs subject to an AMR. The applicant provided this response to the staff in a letter dated November 26, 2002. Therefore, SER Open Item 2.3.3.18-1 is closed because the applicant's written response provides the link to Section 2.3.3.18 that shows the SCs of concern captured within the structural steel component group and is subject to an AMR.

On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.3.3.18.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the crane and hoist SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.3.19 Non-Safety-Related Systems Affecting Safety-Related Systems

As described in SER Section 2.1, the applicant's scoping and screening methodology considered seismic Class II structural components, supports, foundations, and anchorages, but did not originally consider potential non-safety-related/safety-related interactions for seismic Class II piping and components. In a letter dated January 23, 2002, the staff requested the applicant to 1) consider non-safety-related piping systems which are not connected to safety-related piping, but have a spatial relationship such that their failure could adversely impact on the performance of an intended safety function. Furthermore, 2) given the methodology used to identify piping systems that meet the 10 CFR Part 54.4(a)(2) scoping criterion, there may be other non-safety-related system, structures, and components (SSCs) which should be included within the scope of license renewal. Therefore the staff asked the applicant to describe how the applicant will prevent an age-related non-safety-related system, structure, and component (SSC) failure from affecting safety-related SSCs where the potential for spatial interaction exists.

2.3.3.19.1 Summary of Technical Information in the Application

In a letter dated May 21, 2002, in a response to RAIs 2.1.2-3, 2.1.2-4, and 3.3-1, the applicant stated that components of selected non-safety-related systems have the potential for a spatial interaction with safety-related SSCs that could adversely impact the performance of an intended safety function. These non-safety-related systems, which were previously excluded from the scope of license renewal were recategorized as falling within the scope of license renewal and subject to an AMR in accordance with the scoping criterion of 10 CFR 54.4(a)(2).

The following is a list of non-safety-related systems identified as having a potential for interacting with safety-related systems:

- service water system
- reactor building closed cooling water system
- reactor water cleanup system
- chilled water system
- water treatment system
- plant equipment and floor drain system
- process sampling system
- auxiliary steam system
- condensate transfer
- refueling water storage and transfer
- torus water cleanup system
- post accident sampling system

In addition, the applicant expanded the boundary of the following in-scope systems because non-safety-related portions of these systems have the potential for interacting with other safety-related systems, structures, and components:

- reactor pressure vessel instrumentation system
- core spray system
- residual heat removal system
- fuel pool cooling and cleanup system
- control rod drive system
- radiation monitoring system
- reactor recirculation system
- emergency service water system

Certain components of the reactor building closed cooling water system, chilled water system, plant equipment and floor drain system, process sampling system, and torus water cleanup system associated with the primary containment boundary support the primary containment isolation system (PCIS) intended function of containment isolation. The LRA included these components within the scope of license renewal by realigning them (as defined in Section 2.2 of this SER) from the non-safety-related system to the PCIS for the purpose of license renewal. The PCIS is described in Section 2.3.2.3 of the LRA and the realigned valves and piping are included in LRA Table 2.3.2-3. The PCIS is evaluated in Section 2.3.2.3 of this document.

In the RAI response the applicant provided tables that listed the “component groups” for the above non-safety-related systems and expanded-boundary systems that require an AMR. These are presented in the supplemental tables to the LRA within the RAI response. These tables list the component groups and the passive and long-lived components of each group with their passive functions identified and the AMR results for each component. The applicant identified the following component groups for the non-safety-related systems that are subject to an AMR:

- castings and forgings (valve bodies, pump casings, steam traps, strainer bodies)
- piping (pipe, tubing)
- piping specialities (thermowells, flow elements, restricting orifice)

- heat exchangers (shell, channel heads, unit heater tubes, unit heater headers and connections, ventilation heater tubes, ventilation heater headers and connections, drywell cooler tubes, drywell cooler headers, drywell cooler connections)
- vessel (head tank, chemical addition tank, tanks)

The applicant identified the following additional components in the systems whose in-scope boundaries were expanded:

- castings and forgings (valve bodies in condensate storage water, pump casings in fuel pool water),
- piping (tubing in condensate storage water)
- piping specialities (filter bodies and rupture disks in condensate storage water)
- heat exchangers (shell in fuel pool water, channel head in raw water)
- vessel (surge tank in fuel pool water)

All of the components added due to potential non-safety-related/safety-related interactions have a pressure boundary intended function.

2.3.3.19.2 Staff Evaluation

The staff reviewed the LRA and UFSAR to determine whether there is reasonable assurance that the non-safety-related systems affecting safety-related system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

Paragraph (2) of 10 CFR 54.4(a)(2) defines the criteria for determining which plant Criterion 2 systems, structures, and components are within the scope of license renewal. Section 54.4(a)(2) states the following:

> All nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs (a)(1) (i), (ii), or (iii) of this section.

Paragraphs (a)(1)(i), (ii), and (iii) read as follows:

> (1) Safety-related systems, structures, and components which are those relied on to remain functional during and following design basis events (as defined in 10 CFR 50.49 (b)(1)) to ensure the following functions—
>
> > (i) The integrity of the reactor coolant pressure boundary;
> >
> > (ii) The capability to shut down the reactor and maintain it in a safe shutdown condition; or

(iii) The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to those referred to in §50.34(a)(1), §50.67(b)(2), or §100.11 of this chapter, as applicable

The NRC staff position on the 10 CFR Part 54.4(a)(2) scoping criterion states that an applicant should identify and demonstrate that failures of non-safety-related SSCs would not adversely impact on the ability to maintain intended functions of SSCs relied on to meet the requirements of the rule in 10 CFR 54.4(a)(1). Consequently, the staff must have reasonable assurance that the applicant has identified all non-safety-related SSCs that meet the 54.4(a)(2) scoping criterion. When making a determination on the potential for non-safety SSCs adversely impacting safety-related SSCs, an applicant should consider how plant-specific failures of non-safety SSCs and industry failures of such SSCs were considered in its determination. Further, an applicant should consider non-safety SSCs which may not have failed during the current term, but may have a reasonable expectation of failure during the extended term. Therefore, all SSCs that meet with 10 CFR Part 54.4(a)(2), that is all non-safety-related SSCs affecting safety-related intended functions, are in the scope of license renewal.

Additionally, the Statements of Consideration for 54, Section III.b.iii, “Bounding the Scope of Review”, state that:

> Pre-application rule implementation has indicated that the description of systems, structures, and components subject to review for license renewal could be broadly interpreted and result in an unnecessary expansion of the review. To limit this possibility for the scoping category relating to nonsafety-related systems, structures, and components, the Commission intends this non-safety-related category (54.4(a)(2)) to apply to systems, structures, and components whose failure would prevent the accomplishment of an intended function of a safety-related system, structure, or component. An applicant for license renewal should rely on the on the plant’s [Current Licensing Basis] CLB, actual plant-specific experience, industry-wide operating experience, as appropriate, and existing engineering evaluations to determine those non-safety-related systems, structures, and components that are the initial focus of the license renewal review. Consideration of hypothetical failures that could result from system interdependencies that are not part of the CLB and that have not been previously experienced is not required.

As noted in Section 2.1.3, the staff review of the Peach Bottom scoping and screening methodology determined that the applicant did not include piping of non-safety-related systems not connected to safety-related piping within the scope of license renewal. These piping systems may have a spatial relationship in that their failure could adversely impact the performance of an intended safety function. In letters dated January 23, 2002, and February 6, 2002, the staff issued RAIs 2.1.2-3, 2.1.2-4, and 3.3-1 to address these issues.

In a letter dated May 21, 2002, the applicant responded to the RAIs. The applicant identified components of non-safety-related systems (listed above) which fall within the scope of license renewal and are subject to an AMR. However, the applicant’s RAI response did not supply sufficient information to allow the staff to determine, with reasonable assurance, that all of the SSCs with the potential for non-safety to safety-related interactions had been identified and included within the scope of license renewal. The staff asked the applicant to do the following:

- Define the procedure and criteria used to determine the credibility of the spatial interactions of the hazard systems with equipment within the scope of license renewal. Identify the plant area where the potential interactions with safety-related equipment are postulated to occur.

- Explain how non-fluid-containing systems having potential spatial interaction with safety-related systems were evaluated.

- Define the criteria used to designate hazard systems.

- Describe the plant walkdown mentioned in the applicant's May 21, 2002, letter to the NRC and how the results were used to determined which non-safety-related systems, structures, and components were brought within scope.

- Discuss the means by which information that formed the basis for the applicant's conclusions for including the non-safety-related systems within the scope will be documented, auditable, and retrievable, in accordance with 10 CFR 50.37.

This issue was characterized as SER Open Item 2.3.3.19.2-1.

During the staff's July 10, 2002, meeting with the applicant at the Peach Bottom site, and as stated in a letter dated November 26, 2002, the applicant developed Project Level Instruction PLI-008, "Review Process for Non Safety-Related to Safety-Related SC Interactions," to identify non-safety-related systems and components that met the scoping criteria specified in 10 CFR 54.4(a)(2) as a result of potential spatial interactions with safety-related SSCs. The applicant presented the staff with PLI-008 and described how non-safety-related SSCs were included within the scope and subject to AMR.

To address the staff's concerns, the applicant presented its methodology for evaluating non-safety-related systems and the non-safety-related portions of safety-related systems within the scope of license renewal. First, the applicant defined a hazard system (if the system is a hazard it would be included within the scope if it had a potential spatial interaction) as any system that contains a fluid other than air or gas, irrespective of pressure and temperature. Second, once a hazard system was identified the applicant conducted the following evaluation:

- the component record list (CRL) was reviewed for specific location data for individual systems or spaces

- when spaces were evaluated for non-safety-related to safety-related interaction, the results of the evaluations were documented and applied to those systems that occupy those spaces

- plant mechanical piping drawings and equipment location drawings were reviewed in conjunction with the CRL location information to determine where potential spatial interactions could occur.

- walkdowns were performed to verify potential spatial interactions and to identify material information as needed for in-scope non-safety-related components, and the walkdowns were documented in a walkdown file.

For the non-safety-related systems and non-safety-related portions of in-scope systems having potential spatial interaction with safety-related systems, a system-structure matrix was developed. The matrix identifies the evaluation boundaries for the non-safety-related SSCs identified as having spatial interaction with system intended functions meeting the scoping criteria for license renewal. The matrix below identifies the systems that meet the requirements of the 10 CFR 54.4(a)(2) and the evaluation boundaries (i.e., structures) of those systems:

SYSTEM	RB	D/W	D/G	R/W	NSB	CWP	RAB
RPV Instrumentation	X						
Reactor Recirculation	X						
Core Spray	X						
RHR							
Fuel Pool Cooling and Cleanup	X	X					
Control Rod Drive	X						
Radiation Monitoring	X		X				X
Emergency Service Water							X
RWCU	X	X					
Service Water		X					X
Reactor Building closed cooling water	X	X					X
Chilled Water	X	X		X			
Water Treatment	X	X	X				
Plant Equipment and floor drains	X						
Process Sampling	X	X		X			X
Auxiliary Steam	X		X	X	X	X	X
Condensate transfer	X						
Refueling Water Storage and Transfer	X						
Torus Water cleanup	X						
Post Accident Sampling	X						X

Structure legend: RB - Reactor Building; D/W - Drywell (Containment); D/G - Diesel Generator Building; R/W - Radwaste Building; NSB - Nitrogen Storage Building; CWP - Circulating Water Pumphouse; RAB - Reactor Auxiliary Bay

The staff participated in a walkdown of these systems with the applicant during the July 10, 2002, meeting at the Peach Bottom site. The staff verified that non-safety-related systems, listed in the above matrix, could potentially prevent safety-related functions of certain SSCs from being performed if they were to fail. Systems, structures, and components affected by such interactions were the (1) safety-related instrument panel for the emergency core cooling system; (2) high pressure coolant injection alternative control panel; (3) safety-related motor control center; (4) reactor pressure vessel instrumentation panel; and (5) safety-related breakers.

For non-fluid containing SSCs in which a failure could adversely impact the performance of an intended safety function of safety-related SSCs, the applicant completed an operating experience review. The applicant reviewed 24 NRC Information Notices, IE Bulletins and Generic Letters regarding non-fluid environments of ventilation, gas and external environments (air). In addition, the applicant reviewed its plant specific operating experience which included 12 potentially relevant corrective action reports and 57 potentially relevant work orders. The review indicated that no failures due to aging had occurred in the industry for the materials and environments examined. Therefore, the applicant concluded that non-fluid containing components could not affect safety-related SSCs due to leakage or spray.

The applicant, in its response dated November 26, 2002, added additional non-safety-related systems to the scope of license renewal beyond those identified in its May 21, 2002, response to the staff's RAI. The applicant included non-safety-related portions of the reactor recirculation system and the emergency service water system. These systems were already included within the scope of license renewal. However, the evaluation boundary was increased to include non-safety-related portions of each system as a result of potential spatial interaction with other safety-related SSCs. In addition, the applicant included the post accident sampling system to the scope of license renewal as portions of the system posed a potential hazard due to potential spatial interaction in which a failure could adversely impact the performance of an intended function of safety-related SSCs.

To meet the requirements of 10 CFR 54.37, the applicant stated that documents will be created for the above systems within the scope of license renewal because of 10 CFR 54.4(a)(2), similar to those documents created for safety-related systems within the scope of license renewal that meet 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(3). The documents consist of scoping and screening forms, aging management reviews, boundary drawings, CRL updates, and procedure annotations of commitments. Therefore, Open Item 2.3.3.19.2-1 is closed based upon the applicant's response to the Open Item and the staff's review of the November 26, 2002, response which is consistent with the staff's review and plant walkdown of July 10, 2002, at the Peach Bottom site.

On the basis of the above review the staff did not find any other omissions by the applicant of SSCs within the scope of license renewal.

2.3.3.19.3 Conclusions

On the basis of its review the staff concludes there is reasonable assurance that the applicant has adequately identified the non-safety-related SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.4 Steam and Power Conversion Systems

2.3.4.1 Main Steam System

2.3.4.1.1 Summary of Technical Information in the Application

In Section 2.3.4.1 of the LRA, the applicant describes the components of the main steam system that fall within the scope of license renewal and are subject to an AMR. This system is further described in Sections 4.4, 4.11, 6.4.2, and 14.9 of the Peach Bottom UFSAR.

The 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 tests during plant operation with a minimum amount of load reduction. Each main steam line up to and including the main steam line isolation valve external to the primary containment is seismic Class I.

The main steam system provides steam on demand to the HPCI and RCIC system turbines via the “B” and “C” main steam lines, respectively.

Overpressure protection of the reactor pressure vessel is provided via the main steam safety relief valves (SRVs) and safety valves (SVs). This function ensures the integrity of the reactor coolant pressure boundary and associated piping. The capability to depressurize the reactor vessel via the ADS designated SRVs during all normal plant operating conditions and following a design basis event allows the operation of the low pressure ECCS systems should they be required.

The five safety relief valves designated to fulfill the ECCS function, in conjunction with the ADS logic, ensure that the low pressure ECCS systems provide adequate core cooling during accident and post-accident conditions in the event that the high-pressure coolant injection systems are unavailable or unable to maintain level in the vessel.

The main steam system operates in conjunction with the primary containment isolation system to mitigate the consequences of accidents which could result in potential offsite exposure due to a breach of the main steam system. The MSIVs will close on signals indicative of a LOCA or leak in the main steam system to containment. The main steam line flow restrictors limit maximum steam flow under assumed accident conditions of a steam line rupture to a value which ensures that the steam dryer in the reactor vessel remains in place. This feature ensures that fragments from the dryer will not be blown into the steam lines preventing tight closure of the MSIVs. This function also serves to limit steam line flow during a steam line rupture outside of primary containment until the MSIVs can close, thereby limiting potential radioactive release.

The main steam system also allows for a path for alternate shutdown cooling in the event that the shutdown cooling mode of the RHR system cannot be established. This is accomplished by closing the main steam isolation valves, raising the reactor vessel level to the main steam lines, and using no more than two ADS SRVs for low pressure liquid discharge to the suppression pool, and one or more RHR loops operating in the suppression pool cooling mode of the system.

Post-accident containment, holdup, and plateout of MSIV bypass leakage are credited in accident analyses when calculating airborne activities. Plateout of elemental and particulate iodine is credited in steam line piping and the main condenser.

The applicant describes its methodology for identifying the mechanical components within the scope of license renewal in Section 2.1.2 of the LRA. The applicant states that the following intended functions fall within the scope of license renewal:

- delivery of steam to HPCI and RCIC systems
- overpressure protection of the reactor pressure vessel (RPV)
- RPV depressurization
- containment isolation
- steam line flow restriction
- steam flow measurement
- alternate shutdown cooling
- post-accident containment, holdup and plateout of MSIV bypass leakage

Using the methodology described in LRA Section 2.1.2, as specified in 10 CFR 54.21(a)(1), the applicant listed the mechanical component groups subject to an AMR and identified their intended functions in Table 2.3.4-1 of the LRA. The applicant identifies the following component groups:

- vessel (accumulators)
- casting and forging (valve bodies)
- piping (pipe, tubing, SRV Tailpipe and RPV Head Flange Leakoff)
- piping specialties (restricting orifices, dashpots, flexible hoses, flow elements, strainers, condensing chambers, and spargers)

The intended functions for the main steam system components subject to an AMR are pressure boundary integrity, throttle, and spray.

2.3.4.1.2 Staff Evaluation

The staff reviewed section 2.3.4.1 of the LRA and UFSAR sections 4.4, 4.11, 6.4.2, and 14.9 to determine whether there is reasonable assurance that the main steam system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

The staff reviewed the text and diagrams submitted by the applicant in Section 2.3.4.1 of the LRA and the Peach Bottom UFSAR to determine if the applicant adequately identified the SSCs of the main steam system that are in the scope of license renewal. The staff verified that those portions of the main steam system that meet the scoping requirements of 10 CFR 54.4 are included within the scope of license renewal and are identified as such by the applicant in Section 2.3.4.1 of the LRA. The staff then focused its review on those portions of the main steam system that were not identified as being within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4. The staff also reviewed the UFSAR to determine if there were any additional system functions that were not identified in the LRA, and verified that those additional functions did not meet the scoping requirements of 10 CFR 54.4.

The staff then determined whether the applicant had properly identified the SSCs that are subject to an AMR from among those portions of the main steam system that are identified as being within the scope of license renewal. The applicant identifies and lists the SSCs subject to AMR for the main steam system in Table 2.3.4-1 of the LRA using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff performed its review by sampling the SSCs that the applicant determined to be within the scope of license renewal but not subject to AMR to verify that these SSCs performed its intended function with moving parts or with a change in configuration or properties or were subject to replacement based on a qualified life or specified time period.

The applicant identified the portions of the main steam system that are within the scope of license renewal in the drawings referenced in the LRA. The detailed flow diagrams were highlighted to identify those portions of the system that are within the scope of license renewal. The applicant highlighted those components which it believes perform at least one of the scoping requirements of 10 CFR 54.4. The staff compared the LRA flow diagrams to the system drawings and the descriptions in the UFSAR to ensure they were representative of the main steam system. The staff sampled portions of the flow diagram that were not highlighted to verify that these components did not meet any the scoping criteria in 10 CFR 54.4.

By letter dated March 12, 2002, the staff requested additional information regarding the main steam system, as discussed below.

In RAI 2.2-1.1(b), the staff requested additional information about realigned components, that is, components recategorized from one system to another for the purposes of license renewal. The applicant’s response to RAI 2.2-1.1(b) stated, in part, that the following components were realigned to the main steam system:

- the instrument nitrogen system inboard MSIV nitrogen accumulators and associated piping and valves inside containment
- the instrument nitrogen system solenoid valves associated with the main steam system relief valves
- the instrument air system outboard MSIV air accumulators and associated piping and valves outside containment

The staff reviewed LRA Table 2.3.4-1 to confirm that the piping and components realigned from the non-safety-related instrument nitrogen and air systems were, in fact, included in the list of main steam system components subject to an AMR. The staff concluded that the applicant’s realignment process did not omit any SSCs of the instrument nitrogen and air systems associated with the main steam system that require an AMR. Therefore, the staff finds that the applicant’s realignment of SSCs requiring an AMR from the Instrument nitrogen and air systems to the main steam system have been captured in Table 2.3.4-1 of the LRA, and that the applicant’s response to RAI 2.2-1.1(b) relating to the main steam system is acceptable.

RAI 2.3.4.1-1 asked for a copy of drawing LR-M-304, which is listed in the LRA but had not been provided previously. The applicant responded on May 22, 2002, that drawing LR-M-304 does not exist. The LRA reference for this drawing is in error and will be corrected. Based on the above, the staff found the applicant's response acceptable.

According to Section 2.3.4 of the LRA (page 2-94), and Peach Bottom UFSAR Section 14.9, one of the intended functions of the main steam system is post-accident containment, holdup, and plateout of the MSIV bypass leakage. However, this intended function was not included in Table 2.3.4-1. In RAI 2.3.4-2, the staff asked the applicant to explain why this function was not included in the table. In a letter dated May 22, 2002, the applicant stated that as described in Table 2.1-1, the component intended function of pressure boundary includes fission product barrier and fission product retention. Based on the clarification presented above, the staff found the applicant's response acceptable.

On license renewal boundary drawings LR-M-303 (locations C8, E8, F8) and LR-M-351 sheets 1 and 3 (location G2), thermowells (without temperature elements) are shown to fall within the scope of license renewal but are not specifically listed as being subject to an AMR in Table 2.3.4-1. In RAI 2.3.4-3, the staff questioned why these components were not subject to an AMR. In a letter dated May 22, 2002, the applicant stated that the subject thermowells fall within the scope of license renewal and are subject to an AMR; however, the thermowells were inadvertently omitted from LRA Table 2.3.4-1 and LRA Table 3.4.1. The applicant stated that the thermowells will be included in the two subject tables under piping specialties. The staff found the applicant's response acceptable based on the clarification presented above.

On license renewal boundary drawing LR-M-351 (locations C3 and G4), an expansion joint is shown to fall within the scope of license renewal. A review of Section 2.3.2.3, "Primary Containment Isolation System," of the LRA does not indicate that this component was identified as being subject to an AMR. In RAI 2.3.4-4, the staff asked the applicant to clarify the intended function of this expansion joint, and whether it is subject to an AMR. In a letter dated May 22, 2002, the applicant clarified that these components are included in LRA Table 2.4-1, listed as penetrations under the drywell component group. The staff found the response to RAI 2.3.4-4 acceptable, as the applicant clarified that the expansion joint is subject to an AMR.

In Section 2.3.4.1 of the LRA, containment isolation was listed as an intended function, but this function was not listed in Table 2.3.4-1. The containment isolation function is said to be provided by the primary containment isolation system. In RAI 2.3.4-5, the staff asked the applicant to clarify if the containment isolation function should be included as an intended function for various components listed in Table 2.3.4-1. In a letter dated May 22, 2002, the applicant clarified that the containment isolation function identified in LRA Section 2.3.4.1 is a system intended function and not a component intended function, and therefore should not be included in Table 2.3.4-1. The definition of "pressure boundary" in LRA Table 2.1-1 includes the containment isolation function. Based on the above, the staff found the applicant's response acceptable.

License renewal boundary drawing LR-M-303, sheets 1 and 3, indicate that the turbine stop valves are not within the scope of license renewal for Peach Bottom. On the drawing, the turbine stop valves form the boundary between the piping that is within the scope of license renewal and the piping that is out of scope. If the valve body failed, it appears that the piping within the scope of the rule would be unable to perform its intended function. In RAI 2.3.4.1-6, the staff asked the applicant to provide the basis for the exclusion of these valves from the scope of license renewal.

In a letter dated May 22, 2002, the applicant stated that the main steam piping downstream of the outboard main steam isolation valves, up to but not including the turbine stop valves, is classified as safety-related because the piping provides structural support for the safety-related outboard main steam isolation valves. The turbine stop valves are not safety-related and do not have a safety-related intended function, and therefore have not been included in the scope of license renewal. The staff found the applicant's response acceptable on the basis that the turbine stop valves do not have a pressure boundary intended function.

On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.3.4.1.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the main steam SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.4.2 Main Condenser

2.3.4.2.1 Summary of Technical Information in the Application

In Section 2.3.4.2 of the LRA, the applicant described the components of the main condenser that fall within the scope of license renewal and are subject to an AMR. This system is further described in Sections 11.3 and 14.9 of the Peach Bottom UFSAR.

The main condenser provides a heat sink for the turbine exhaust steam, turbine bypass steam, and other flows. 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 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 section 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.

The Peach Bottom accident analyses evaluated MSIV bypass leakage as part of primary containment leakage. This is treated as a ground-level release, with credit for holdup and plateout (elemental and particulate iodine only) in steam line piping and the condenser. This leakage is to the condenser, which is assumed to leak at 1 percent of volume per day.

The applicant described its methodology for identifying the mechanical components within the scope of license renewal in Section 2.1.2 of the LRA. The applicant stated that the main condenser provides for post-accident containment, holdup, and plateout of MSIV bypass leakage and, therefore, is within the scope of license renewal. The intended function for the main condenser components subject to an AMR is also post-accident containment, holdup, and plateout.

Using the methodology described in LRA Section 2.1.2, as specified in 10 CFR 54.21(a)(1), the applicant listed the mechanical component groups subject to an AMR and identified their intended functions in Table 2.3.4-2 of the LRA. The applicant identified the main condenser as the component requiring an AMR.

2.3.4.2.2 Staff Evaluation

The staff reviewed Section 2.3.4.2 of the LRA and UFSAR Sections 11.3 and 14.9 to determine whether there is reasonable assurance that the main condenser system components, and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

The staff reviewed the text and diagrams submitted by the applicant in Section 2.3.4.2 of the LRA and the Peach Bottom UFSAR to determine if the applicant adequately identified the SSCs of the main condenser that are in the scope of license renewal. The staff verified that those portions of the main condenser that meet the scoping requirements of 10 CFR 54.4 are included within the scope of license renewal and are identified as such by the applicant in Section 2.3.4.2 of the LRA. The staff then focused its review on those portions of the main condenser that were not identified as being within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4. The staff also reviewed the UFSAR to determine if there were any additional system functions that were not identified in the LRA, and verified that those additional functions did not meet the scoping requirements of 10 CFR 54.4.

The staff then determined whether the applicant had properly identified the SSCs that are subject to an AMR from among those portions of the main condenser that are identified as being within the scope of license renewal. The applicant identifies and lists the SSCs subject to AMR for the main condenser in Table 2.3.4-2 of the LRA using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff performed its review by sampling the SSCs that the applicant determined to be within the scope of license renewal but not subject to AMR to verify that these SSCs performed their intended function with moving parts or with a change in configuration or properties or were subject to replacement based on a qualified life or specified time period.

The applicant identified the portions of the main condenser that are within the scope of license renewal in the drawings referenced in the LRA. The detailed flow diagrams were highlighted to identify those portions of the system that are within the scope of license renewal. The applicant highlighted those components which it believes perform at least one of the scoping requirements of 10 CFR 54.4. The staff compared the LRA flow diagrams to the system drawings and the descriptions in the UFSAR to ensure they were representative of the main condenser. The staff sampled portions of the flow diagram that were not highlighted to verify that these components did not meet any the scoping criteria in 10 CFR 54.4.

On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.3.4.2.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the main condenser SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.3.4.3 Feedwater System

2.3.4.3.1 Summary of Technical Information in the Application

In Section 2.3.4.3 of the LRA, the applicant described the feedwater system components that fall within the scope of license renewal and are subject to an AMR. This system is further described in Sections 4.11, 7.10, and 11.8 of the Peach Bottom UFSAR. The system boundaries of the feedwater system are shown in license renewal drawings LR-M-308 and LR-M-351, both Rev. A.

The feedwater system is safety-related from the outermost primary containment isolation valve to the RPV. The portion of the feedwater system from the inlet of the drain cooler up to, but not including, the outermost primary containment isolation valve is non-safety-related.

During normal plant operation, the feedwater system receives its supply of water from the outlet of the condensate demineralizers. 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 entering the reactor feed pumps, thus increasing the heat cycle efficiency. The outlets of the three heater strings are cross-connected and provide a common suction header for the three reactor feed pumps. The reactor feed pumps are mounted in parallel with each having an individual suction valve, discharge check valve, and discharge valve. The reactor feed pumps discharge to a common discharge header that connects to two feedwater headers. These two feedwater headers contain inboard and outboard containment isolation valves. Inside containment, these two feedwater headers each split into three piping runs for a total of six, which then go to the RPV. The feedwater system provides the injection path for HPCI and RCIC during transient and accident conditions. HPCI and RCIC join the feedwater system outside the primary containment. Flow is then channeled through the feedwater piping to the RPV.

The applicant described its methodology for identifying the mechanical components within the scope of license renewal in Section 2.1.2 of the LRA. The applicant stated that the following functions of the feedwater system fall within the scope of license renewal:

- HPCI and RCIC injection - The feedwater system provides an injection path into the RPV for both HPCI and RCIC during transient or accident conditions.

- Primary containment isolation - The feedwater system provides primary containment isolation to prevent primary containment leakage under transient and accident conditions.

Using the methodology described in LRA Section 2.1.2, as specified in 10 CFR 54.21(a)(1), the applicant listed the mechanical component groups subject to an AMR and identified their intended functions in Table 2.3.4-3 of the LRA. The applicant identified the following component groups:

- casting and forging
- piping
- piping specialties

LRA Table 2.3.4-3 lists pressure boundary integrity as the intended function for the feedwater system components subject to an AMR.

2.3.4.3.2 Staff Evaluation

The staff reviewed Section 2.3.4.3 of the LRA, UFSAR Sections 4.11, 7.10, and 11.8, and license renewal boundary drawings to determine whether there is reasonable assurance that the feedwater system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

The applicant identified and listed the components subject to an AMR for the feedwater system in Table 2.3.4-3 of the LRA using the screening methodology described in Section 2.1.3 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff subsequently performed a review of the implementation of the methodology for the feedwater system by sampling the components identified as falling within the scope of license renewal but not subject to an AMR to verify that these components perform their intended functions with moving parts or with a change in configuration or properties or are subject to replacement base on a qualified life or specified time period.

In Section 2.3.4.3 of the LRA, the applicant listed two license renewal boundary diagrams, LR-M-308 and LR-M-351, for the feedwater system. The applicant also identified the mechanical components subject to an AMR and their intended functions in Table 2.3.4-3 of the LRA. The boundary diagrams were highlighted to identify those portions of the system that were included within the scope of license renewal. The applicant highlighted those components, which it believes perform at least one of the scoping requirements of 10 CFR 54.4. The staff compared the boundary diagrams to the system description in the UFSAR to ensure that it was representative of the feedwater system. The staff also sampled portions of the boundary diagrams that were not highlighted to ensure these components did not perform any of the functions as defined in 10 CFR 54.4(b).

After completing the initial review, in a letter dated March 12, 2002, the staff requested additional information regarding the feedwater system, and the applicant submitted responses to the RAIs, as discussed below.

Section 2.3.4.3 of the LRA provided a list of the intended functions within the scope of license renewal. One of the functions listed is containment isolation. However, Table 2.3.4-3 does not list this intended function. In RAI 2.3.4-1, the staff asked the applicant to explain why this function was not included in the table.

In a letter dated May 22, 2002, the applicant clarified that the containment isolation function identified in LRA Section 2.3.4.3 is a system intended function and not a component intended function, and therefore should not be included in Table 2.3.4-3. The applicant further stated that the definition of “pressure boundary” in LRA Table 2.1-1 includes the containment isolation function. The staff found the applicant’s clarification in response to RAI 2.3.4-1 to be acceptable.

On boundary drawing LR-M-308, reducers and increasers were shown to fall within the scope of license renewal. However, these piping components were not specifically listed in Table 2.3.4-3 as subject to an AMR. In RAI 2.3.4-2, the staff asked the applicant to justify their exclusion from the table. In a letter dated May 22, 2002, the applicant clarified that the reducers and increasers are fittings and part of the piping system, and therefore are included in Table 2.3.4-3 in the “pipe” component group. The staff found the applicant’s clarification in response to RAI 2.3.4-2 to be acceptable.

License renewal boundary drawing LR-M-351, sheets 1 through 4, show the tie into the feedwater system from the high-pressure coolant injection system. For example, location F8 shows an expansion joint which falls within the scope of license renewal. A review of Section 2.3.2.3, “Primary Containment Isolation System,“ of the LRA does not indicate that this component is subject to an AMR. In RAI 2.3.4-3, the staff asked the applicant to clarify the intended function of this expansion joint, and whether it requires an AMR. In a letter dated May 22, 2002, the applicant clarified that the expansion joint shown on drawing LR-M-351 is the drywell penetration bellows, and that it is in the scope of license renewal and is identified in Table 2.4-1 of Section 2.4.1, “Containment Structure.” The staff found the applicant’s clarification in response to RAI 2.3.4-3 to be acceptable.

On license renewal boundary drawing LR-M-308 sheets 1 and 3 (locations B7, E7, and G7), a flow element is shown. The only intended function listed in Table 2.3.4-3 is pressure boundary. In RAI 2.3.4-4, the staff asked whether “throttle” should be included as an intended function. In a letter dated May 22, 2002, the applicant clarified that “throttle” is not an intended function for the flow elements in the feedwater system. The feedwater system intended functions are to provide an injection path to the RPV for HPCI and RCIC during accident conditions and to isolate the primary containment. The component intended function of “pressure boundary” supports these system intended functions.

The staff reviewed that applicant’s response to RAI 2.3.4-4 and determined that the pressure drop produced by these flow elements is sensed to produce a flow measurement signal for the feedwater control system and does not directly initiate a containment isolation signal or reactor trip. The feedwater control system regulates the flow of feedwater to the reactor vessel; its malfunction is an analyzed event whose effects do not fall within the criteria of

10 CFR 54.4(a)(1). Therefore, the staff finds that flow restriction need not be included as an intended function, and the applicants clarification in response to RAI 2.3.4-4 is acceptable.

On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.3.4.3.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the feedwater SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.4 Scoping and Screening Results: Structures and Component Supports

The applicant described the structures and structural components that are within the scope of license renewal and subject to an AMR in the following sections of the LRA: 2.4.1 “Containment Structure”; 2.4.2 “Reactor Building Structure”; 2.4.3 “Radwaste Building and Reactor Auxiliary Bay”; 2.4.4 “Turbine Building and Main Control Room Complex”; 2.4.5 “Emergency Cooling Tower and Reservoir”; 2.4.6 “Station Blackout Structure and Foundations”; 2.4.7 “Yard Structures”; 2.4.8 “Stack”; 2.4.9 “Nitrogen Storage Building”; 2.4.10 “Diesel Generator Building”; 2.4.11 “Circulating Water Pump Structure”; 2.4.12 “Recombiner Building”; 2.4.13 “Component Supports”; 2.4.14 “Hazard Barriers and Elastomers”; 2.4.15 “Miscellaneous Steel”; 2.4.16 “Electrical and Instrumentation Enclosures and Raceways”; and 2.4.17 “Insulation.” The license renewal boundary diagram referenced for structures is LR-S-001. The scoping and screening methodology for identifying SSCs subject to an AMR is addressed in Section 2.1 of this report.

For each of the structures within the scope of license renewal, the applicant provided the following information:

- general description of the structure
- intended functions of the structure within the scope of license renewal
- reference to the applicable UFSAR sections
- reference to the applicable license renewal boundary diagrams
- list of the components or component groups that require an AMR and associated component intended functions and environments (for each structure, the tables were sorted by component group and then by environment)

In addition to the structures within the scope of license renewal presented in this section, the applicant evaluated several structural component groups, such as component supports as commodities. Commodity groups were determined on the basis of similar design or similar materials and similar environments. For each of the structural commodities, the applicant provided the following information:

- general description of the commodity
- list of the components or component groups that require aging management review and the associated component intended functions and environments

The staff reviewed Section 2.4 of the LRA, license renewal site diagram LR-S-001, applicable sections and figures of the Peach Bottom UFSAR, and additional information provided by the applicant in response to staff's RAIs, to determine whether there is reasonable assurance that all SSCs have been identified that are within the scope of license renewal as specified in 10 CFR 54.4(a) and are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The results of this review are discussed in the following sections.

2.4.1 Containment Structure

2.4.1.1 Summary of Technical Information in the Application

In Section 2.4.1 of the LRA, the applicant provided a description of the primary containment and its intended functions that place the containment structure and its structural components within the scope of license renewal and subject to an AMR. In each unit, the containment structure consists of the primary containment and internal structural steel. The primary containment of each unit has a Mark I containment that consists of a drywell, a suppression chamber (in the shape of a torus), and a connecting vent system between the drywell and the suppression chamber.

The containment structure is part of a "multibarrier" system with a primary barrier consisting of the primary containment and its pressure suppression system. The secondary barrier is the reactor building, which has a system to limit the ground-level release of airborne radioactive material from the secondary containment. In the event of a design basis LOCA , the containment structure contains the released steam to limit the release of fission products from the accident to the reactor building.

The primary containment is a seismic Class I structure that encloses the reactor vessel, the reactor coolant recirculating system, and other branch connections of the reactor coolant system. In addition to the drywell and connected pressure suppression chamber, it includes isolation valves, vacuum breakers, containment cooling systems, and other service equipment. The drywell is a steel pressure vessel in the shape of a light bulb. The pressure suppression chamber is a torus-shaped steel pressure vessel below and around the drywell. The drywell is enclosed in reinforced concrete for the purpose of shielding. The stiffened pressure suppression chamber contains approximately 125,000 ft^3 of water and has a gas space volume above the pool. The pressure suppression chamber is supported on braced vertical columns which carry the loading to the reinforced concrete foundation slab of the reactor building.

Internal structural steel is provided at various elevations of the primary containment drywell and the pressure suppression chamber. The internal structural steel provides structural support to the safety-related and non-safety-related systems and equipment inside the primary containment drywell. It also provides personnel access to the equipment for maintenance and testing.

The containment structure is further discussed in Sections 5.2, 14.6, and Appendix M.3 of the UFSAR. The license renewal drawing referenced for the containment structure is LR-S-001.

The applicant determined that the following intended functions for the containment structure fall within the scope of license renewal:

- Primary containment - The primary containment provides an essentially leak-tight fission product barrier.

- Primary containment pressure suppression - The containment structure supports the pressure suppression by providing the following functions:

  - LOCA vent system steam discharge pressure suppression
  - Steam discharge pressure suppression
  - Suppression pool water inventory and supply

- Physical support - The containment structure provides physical support for the safety-related and non-safety-related systems and equipment during normal and abnormal loading conditions.

The applicant described its process for identifying the structural/civil components falling within the scope of license renewal and subject to an AMR in Section 2.1 of the LRA. On the basis of this methodology, the applicant identified the following containment component groups in Table 2.4-1 as the passive and long-lived component groups subject to an AMR:

- reinforced concrete (reactor pedestal, foundation, floor slab)
- unreinforced concrete (sacrificial shield wall)
- drywell (shell, head, CRD removal hatch, equipment hatch, personnel airlock, access manhole and inspection ports, penetrations, penetration bellows, gaskets, o-rings and packing materials)
- pressure suppression chamber (shell, ring girders, column and saddle supports, seismic restraints, lubrite plates, access hatches, penetrations and elastomers [gaskets])
- vent system (vent lines, vent line bellows, header and downcomers, downcomer bracing, vent system supports)
- structural steel (reactor vessel pedestal steel, sacrificial shield wall steel, sacrificial shield wall stabilizer, radial beam seats, lubrite plates, jet impingement shields, pipe whip restraints, missile barriers and radiation shields)

The intended functions of these components include providing (1) structural support, (2) shelter, protection, and/or radiation shielding, (3) pressure boundary, and (4) fission product barrier.

2.4.1.2 Staff Evaluation

The staff reviewed Section 2.4.1 of the LRA, Sections 5.2 and 14.6 and Appendix M.3 of the Peach Bottom UFSAR, relevant staff SERs, the IPE and IPEEE, and additional documents and drawings provided by the applicant in response to staff's RAIs to determine whether there is reasonable assurance that the primary containment system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

In a letter dated March 12, 2002, the staff requested additional information on the primary containment intended functions and the components subject to an AMR listed on Table 2.4-1 of the LRA. In RAI 2.4.1-1, the staff acknowledged that the LRA listed the following three intended functions for the primary containment structure:

- provide an essentially leak-tight fission product barrier
- support pressure suppression
- provide physical support for safety-related and non-safety-related systems and equipment during normal and abnormal loading conditions

The staff inquired of the applicant whether additional intended functions should be attributed to primary containment such as protecting safety-related equipment from missiles, high-energy line breaks, fires, and environmental hazards.

In response to RAI 2.4.1-1 (in a letter dated May 22, 2002), the applicant stated that the primary containment intended functions specified in the LRA were consistent with its safety design basis as described in the UFSAR, Section 5.2. The primary containment did not provide protection against missiles, high-energy line breaks, fire, or environmental hazards. This protection was provided by the components of the reactor building structure, which enclosed the primary containment. The applicant referred to Figure M 1.1 of the UFSAR, which outlined the boundary of the primary containment structure, and to Figure 12.1.7 of the UFSAR, which showed reactor building concrete that protected the primary containment structure.

On the basis of this response, the staff found that the applicant has properly identified the primary containment intended functions.

In RAI 2.4.1-2, the staff indicated that Section 2.4.1 of the LRA stated that the drywell was enclosed in reinforced concrete for shielding purposes. Table 2.4-1 of the LRA listed reinforced concrete foundation and floor slabs that function as radiation shielding. However, the reinforced concrete around the drywell was not included. The staff asked the applicant to clarify whether the reinforced concrete around the drywell was part of the containment structure and subject to an AMR.

In response to RAI 2.4.1-2, the applicant stated that the reinforced concrete around the drywell was not part of the primary containment structure but was a part of the reactor building structure. The reinforced concrete around the drywell is subject to AMR as indicated in Table 3.5-2 of the LRA. The staff found this clarification to be acceptable .

Based on the information provided in the LRA and the UFSAR, the staff sampled several components in Table 2.4-1 of the LRA to determine whether the applicant properly identified the passive and long-lived structural components on the list of components as being subject to an AMR. On the basis of the above review, the staff did not find any omissions by the applicant.

2.4.1.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the primary containment structure SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.4.2 Reactor Building Structure

2.4.2.1 Summary of Technical Information in the Application

For each unit, the reactor building is a seismic Class I structure that completely encloses the primary containment and auxiliary systems of the nuclear steam supply system, and houses the associated spent fuel storage pool, dryer and separator storage pool, and reactor well. The building substructure from the foundation mat to the refueling floor is a reinforced concrete structure. Above this floor, the building superstructure consists of metal siding and roof decking supported on a structural steel framework. The foundation of the building consists of a reinforced concrete mat supported on rock. This foundation mat also supports the primary containment and its internals, including the reactor vessel pedestal. The exterior wall and some of the interior walls of the building above the foundation are constructed with cast-in-place concrete. Other interior walls are normal-weight concrete block walls. The 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 the walls and slabs was governed by structural design or shielding requirements. The building superstructure is a steel-framed structure that is cross-braced to withstand wind and earthquake forces and support metal siding, metal roof deck, and roofing. The steel frame also supports a runway for the 125-ton traveling reactor building crane.

The reactor building is further discussed in Section 12.2 and Appendix C of the UFSAR. The license renewal drawing referenced for the reactor building is LR-S-001.

The applicant determined that the following intended functions for the reactor building structure fall within the scope of license renewal:

- Physical support - The reactor building provides physical support for safety-related and non-safety-related systems and equipment during normal, severe environmental, extreme environmental, and abnormal loading conditions.

- Protection - The reactor building provides protection for safety-related and non-safety-related systems and equipment from external, internal, and environmental hazards.

- Containment - The reactor building provides a secondary containment boundary to contain any release of radioactive material outside the primary containment.

- Fire protection - The reactor building provides rated fire barriers or retards a fire from spreading to adjacent areas of the plant.

- Storage - The spent fuel pool portion of the reactor building provides storage for spent fuel, new fuel, and spent fuel storage casks.

- Water volume - The spent fuel pool holds the volume of water necessary for shielding, cooling, and reactivity control during normal plant operation.

- Reactivity management - The spent fuel storage racks maintain spent fuel in subcritical configuration having a k(eff) less than or equal to 0.95.

In Section 2.1 of the LRA, the applicant described its process for identifying the structural/civil components within the scope of license renewal and subject to an AMR. On the basis of this methodology, the applicant identified, in Table 2.4-2, the following reactor building structural component groups subject to an AMR:

- reinforced concrete (walls, slabs, columns, beams, foundation, block walls)
- fuel pool liner
- fuel pool gates
- fuel storage racks
- Boraflex absorbers
- component supports
- structural steel (structural steel, reinforced concrete embedment, pipe whip restraints, missile barrier, metal siding, roof deck, blowout panels)

The intended functions of the concrete components include providing (1) structural support, (2) fire barrier, (3) shelter, protection, and/or radiation shielding, (4) flood barrier, (5) fission product barrier, (6) missile barrier, (7) HELB shielding and (8) fluid containment. The fuel pool liner and gates have the intended function of maintaining pressure boundary integrity. The Boraflex absorbers have the intended function of absorbing neutrons. The fuel storage racks, component supports, and structural steel components have the intended function of structural support.

2.4.2.2 Staff Evaluation

The staff reviewed Section 2.4.2 of the LRA, the relevant Peach Bottom UFSAR sections, including Section 12.2 and Appendix C, relevant staff's SERs, the IPE and IPEEE, and additional drawings and documents provided by the applicant in response to the staff's RAIs to determine whether there is reasonable assurance that the reactor building structure system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

In a letter dated March 12, 2002, the staff requested additional information on the reactor building components listed on Table 2.4-2 of the LRA. Section 5.2.3.2 of the UFSAR (page 5.2-5) states that "shielding over the top of the drywell is provided at the refueling floor by a removable, segmented, reinforced concrete shield plug." Table 2.4-1 of the LRA lists a steel drywell head subject to an AMR, but the concrete shield plug is not included. Table 2.4-2 of the LRA lists reinforced concrete walls, slabs, columns, beams, and foundation as the components subject to an AMR. However, the drywell shield plug (as addressed in the UFSAR) is not included. In RAI 2.4.2-1, the staff asked the applicant why the drywell shield plug should not be within the scope of license renewal and subject to an AMR.

In response to RAI 2.4.2-1 (in a letter dated May 22, 2002), the applicant stated that the reinforced concrete drywell shield plugs described in Section 5.2.3.2 of the UFSAR were within the scope of license renewal and subject to an AMR. These plugs are considered to be part of the reactor building refueling floor slab and were included in Table 3.5-2 of the LRA with reinforced concrete slabs. The staff found the applicant's response to the RAI to be acceptable.

Based on the information provided in the LRA and the UFSAR, the staff sampled several components to determine whether the applicant properly identified the passive, long-lived structural components on the list of components subject to an AMR in Table 2.4-2 of the LRA.

On the basis of the above review the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.4.2.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the reactor building structure SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.4.3 Radwaste Building and Reactor Auxiliary Bay

2.4.3.1 Summary of Technical Information in the Application

In Section 2.4.3 of the LRA, the applicant provided a description of the radwaste building and reactor auxiliary bay. These structures are connected to the control room and are located between the two reactor buildings. This complex is designed as a seismic Class I structure. Though located between the reactor buildings, the radwaste building is structurally separated from them. The radwaste building houses various components of the radwaste system, the standby gas treatment system, and associated equipment. It also houses the recirculation system motor generator sets for the two units of the power plant, along with the heating and ventilating equipment for the radwaste building and the main control room. The adjoining reactor auxiliary bay houses HPCI and RCIC turbine pumps and RHR equipment.

The building is founded on rock with a reinforced concrete mat. All walls except the west wall are concrete up to the roof. The west wall consists of concrete and metal siding for its full height. The HPCI and RCIC equipment is protected by concrete walls and floor slabs for protection from floods, missiles, and tornados. The heating and ventilating equipment, located at an elevation of 165 ft, is considered essential for a safe shutdown of the plant, and thus is protected from tornado missiles.

Additional information on the radwaste building and reactor auxiliary bay is provided in UFSAR Section 12.2 and Appendix C. The license renewal drawing referenced for the radwaste building and reactor auxiliary bay is LR-S-001.

The applicant determined that the following intended functions for the radwaste building and reactor auxiliary bay fall within the scope of license renewal:

- Physical support - The radwaste building and reactor auxiliary bay provide physical support for safety-related and non-safety-related systems and equipment during normal, severe environmental, extreme environmental, and abnormal loading conditions.

- Protection - The radwaste building and reactor auxiliary bay provide protection for safety-related and non-safety-related systems and equipment from external, internal, and environmental hazards.

- Fire protection - The radwaste building and reactor auxiliary bay provide rated fire barriers or retard a fire from spreading to adjacent areas of the plant.

The applicant described its process for identifying the structural/civil components falling within the scope of license renewal and subject to an AMR in Section 2.1 of the LRA. On the basis of this methodology, the applicant identified, in Table 2.4-3, the following radwaste building and reactor auxiliary bay component groups as the passive and long-lived component groups which are subject to an AMR:

- reinforced concrete (walls, slabs, columns, beams, foundation, block walls)
- structural steel (structural steel, reinforced concrete embedments, jet impingement shields, missile barrier)

The intended functions of the concrete components include providing (1) structural support, (2) fire barrier, (3) shelter, protection, and/or radiation shielding, (4) flood barrier, (5) missile barrier, and 6) HELB shielding. Intended functions of the structural steel components include structural support, HELB shielding, and missile barrier.

2.4.3.2 Staff Evaluation

The staff reviewed Section 2.4.3 of the LRA, Section 12.2 and Appendix C of the Peach Bottom UFSAR, relevant staff SERs, and the IPE and IPEEE to determine whether there is reasonable assurance that the radwaste building and reactor auxiliary bay system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

In a letter dated March 12, 2002, the staff requested additional information on radwaste building and reactor auxiliary bay components subject to an AMR listed on Table 2.4-3 of the LRA. In RAI 2.4.3-1, the staff indicated that Section 2.4.3 of the LRA stated that the west wall of the radwaste building and reactor auxiliary bay consisted of concrete and metal siding for its full length. However, metal siding was not explicitly mentioned under structural steel in Table 2.4-3. The staff noted that metal siding was explicitly mentioned in reviews of other structures such as the reactor building and asked the applicant whether the metal siding was within the scope of license renewal.

In a letter dated May 22, 2002, in response to RAI 2.4.3-1, the applicant indicated that scoping and screening of radwaste building components concluded that the metal siding performed no intended functions under 10 CFR 54.4. The design function of the siding was to protect non-safety-related SSCs housed in the building from the weather. It was not designed to protect safety-related SSCs in the building. The safety-related SSCs were enclosed in reinforced concrete compartments to ensure adequate protection from extreme environmental conditions such as tornadoes and tornado missiles. The siding also was not required for the secondary containment function (fission product barrier), unlike the reactor building siding. The staff found the applicant's response to RAI 2.4.3-1 to be acceptable.

Using the information provided in the LRA and the UFSAR, the staff sampled several components to determine whether the applicant properly identified, in Table 2.4-3 of the LRA, the passive, long-lived structural components that are subject to an AMR. On the basis of this review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.4.3.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the radwaste building and reactor auxiliary bay SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.4.4 Turbine Building and Main Control Room Complex

2.4.4.1 Summary of Technical Information in the Application

In Section 2.4.4 of the LRA, the applicant provided a description of the turbine building and main control room complex. The turbine building is nominally 600 ft by 150 ft in plan and houses both turbine-generators, one for each unit, and other auxiliary plant equipment. This building is founded on rock at various elevations below an elevation of 116 ft. The external and some internal walls are concrete up to the operating floor. The structure above this level is metal siding and deck above a 20-ft band of precast concrete wall panels, all supported by structural steel frames. Frames also support two 110-ton overhead bridge cranes in tandem.

Each turbine-generator is mounted on a concrete pedestal nominally 225 ft by 42 ft and 50 ft high. The pedestals are supported on a concrete mat and founded on rock. The turbine building is designed with the seismic design criteria for Zone 1 established by the Uniform Building Code. The turbine building is located east of the two reactor buildings and is separated from them by a gap to accommodate movements of the structures during an earthquake. The main control room, the cable spreading room, computer room, battery rooms, and emergency switchgear rooms are located in the center portion of the turbine building.

The failure of the turbine building will not impair the safety function of any seismic Class I structure or equipment inside it or adjacent to it. The turbine building and main control room complex is discussed in UFSAR Section 12.2 and Appendix C. The license renewal drawing referenced for the turbine building is LR-S-001.

The applicant determined that the following intended functions for the turbine building and main control room complex fall within the scope of license renewal:

- Physical support - The turbine building provides physical support for safety-related and non-safety-related systems and equipment during normal, severe environmental, extreme environmental, and abnormal loading conditions.

- Protection - The turbine building provides protection for safety-related and non-safety-related systems and equipment from external, internal, and environmental hazards.

- Leak-tightness - The control room provides airtight containment for the habitable areas housed within.

- Fire protection - The turbine building provides rated fire barriers and retards a fire from spreading to adjacent areas of the plant.

- Support and protection - The turbine building provides support and protection for the condensers that are credited for the accident analysis in UFSAR Chapter 14.

The applicant described its process for identifying the structural/civil components falling within the scope of license renewal and subject to an AMR in Section 2.1 of the LRA. On the basis of this methodology, the applicant identified, in Table 2.4-4, the following turbine building and main control room complex component groups as the passive and long-lived component groups subject to an AMR:

- reinforced concrete (walls, slabs, columns, beams, foundation, block walls)
- structural steel (structural steel, reinforced concrete embedments, missile barrier)

The intended functions of the concrete components are providing (1) structural support, (2) fire barrier, (3) shelter, protection, and/or radiation shielding, (4) flood barrier, (5) missile barrier, and (6) HELB shielding. The intended functions of the structural steel components are structural support and missile barrier.

2.4.4.2 Staff Evaluation

The staff reviewed Section 2.4.4 of the LRA, Section 12.2 and Appendix C of the Peach Bottom UFSAR, relevant staff SERs, and the IPE and IPEEE to determine whether there is reasonable assurance that the turbine building and main control room complex system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

In a letter dated March 12, 2002, the staff requested additional information on the turbine building and main control room complex components subject to an AMR listed on Table 2.4-4 of the LRA. In RAI 2.4.4-1, the staff indicated that Section 2.4.4 of the LRA described the turbine building structure as follows: “The structure above this level is metal siding and deck above a 20-ft band of precast concrete wall panels all supported by structural steel frames.” However, metal siding was not included in Table 2.4-4. The staff stated that metal siding was identified as a component subject to an AMR for other structures, including the reactor building structure and SBO structure.

In a letter dated May 22, 2002, in response to RAI 2.4.4-1, the applicant indicated that the scoping and screening of turbine building and main control room complex components concluded that the metal siding performed no intended functions under 10 CFR 54.4. The design function of the siding was to protect non-safety-related SSCs housed in the building from the weather. It was not designed to protect safety-related SSCs in the building. The safety-related SSCs were enclosed in reinforced concrete compartments to ensure adequate protection from extreme environmental conditions such as tornadoes and tornado missiles. The siding also was not required for the secondary containment function (fission product barrier), unlike the reactor building siding. The staff found the applicant's response to RAI 2.4.4-1 to be acceptable.

In RAI 2.4.4-2, the staff indicated that Section 2.4.4 of the LRA identified leak-tightness as an intended function for the turbine building and main control room complex: "Leak-tightness - The control room provides airtight containment for the habitability areas housed within." The staff believed that the walls separating the main control room complex from the turbine building should not be completely air-tight, as during loss of offsite power operation, control room ventilation exhaust appeared to be by leakage directly through the walls to the adjoining turbine building (see LR-M-384, sheet 3, locations D4, D5). Controlling the amount of leakage (both infiltration and exfiltration) was not listed as an intended function of the control room complex roof or walls in Table 2.4-4 of the LRA.

In response to RAI 2.4.4-2, the applicant indicated that the control room was not designed to be completely air-tight or leak-proof. Thus, the leak-tightness intended function as defined in the LRA Section 2.4.4, should not be interpreted to imply it was. The structure was designed to be maintained at a slightly positive pressure with respect to the surrounding areas during normal operation and accident conditions. This function supported the control room ventilation system "ventilation" intended function, described in LRA Section 2.3.3.8 and required by the Peach Bottom Units 2 and 3 technical specifications. The applicant also indicated that control room ventilation exhaust during loss of offsite power was exfiltrated through the floor, ceiling, and walls to the adjacent turbine building. However, controlling the amount of exfiltration leakage was not identified as a design basis function for the control room structure or its structural components. The function was provided by normal leakage through sealed penetrations, door jams, and concrete joints while maintaining positive pressure as required by the technical specifications. The applicant concluded that controlling exfiltration was not an intended function of the control room structure.

The staff's concern is that over the years the main control room complex may become too leak-tight (from multiple coats of paint and sealant) to allow adequate air circulation when forced circulation exhaust is unavailable. The applicant's response did not directly address this concern, but the staff considered the response acceptable on the following basis: (1) The building was not designed to be completely air-tight or leak-proof, and therefore it is highly unlikely that exfiltration will be insufficient to support adequate air recirculation, and (2) forced air exhaust will be unavailable only during SBO events, during which the control room complex doors and louvers could be opened if needed.

Using the information provided in the LRA and the Peach Bottom UFSAR, the staff sampled several components to determine whether the applicant properly identified, in Table 2.4-4 of the LRA, the passive, long-lived structural components on the list of components that are subject to an AMR. On the basis of the above review the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.4.4.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the turbine building and main control room complex SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.4.5 Emergency Cooling Tower and Reservoir

2.4.5.1 Summary of Technical Information in the Application

In Section 2.4.5 of the LRA, the applicant provided a description of the emergency cooling tower and reservoir. The emergency cooling tower and reservoir and associated mechanical and electrical equipment are classified as seismic Class I. The Class I elements of the emergency cooling tower and reservoir structure are founded on rock. The reservoir of the emergency cooling tower has a 1-week water storage capacity, and is a reinforced concrete tank structure approximately 25 ft deep with a precast, prestressed concrete roof. The tank structure is founded on rock.

The cooling tower is a mechanical induced draft type, consisting of three cells. The reservoir and tower facility is a reinforced concrete structure. The cooling tower fill consists of vitreous clay tiles of the multicell block design. Peach Bottom UFSAR Sections 10.24 and 12.2 describe the emergency cooling tower and reservoir in detail. The license renewal drawing referenced for the emergency cooling tower structure is LR-S-001.

The applicant determined that the following intended functions for the emergency cooling tower and reservoir fall within the scope of license renewal:

- Physical support - The emergency cooling tower and reservoir provide physical support for safety-related and non-safety-related systems and equipment during normal, severe environmental, extreme environmental, and abnormal loading conditions.

- Protection - The emergency cooling tower and reservoir provide protection for safety-related and non-safety-related systems and equipment from external, internal, and environmental hazards.

- Fire protection - The emergency cooling tower and reservoir provide rated fire barriers or retards a fire from spreading to adjacent areas of the plant.

- Emergency heat sink - The emergency cooling tower and reservoir provides sufficient capacity for removing the sensible and decay heat from the reactor's primary systems so that both reactors can be shut down in the event of unavailability of the normal heat sink.

- Sustained operation - The emergency cooling tower and reservoir provide sufficient storage water capacity to permit emergency cooling tower operation until a makeup water supply can be established.

The applicant described its process for identifying the structural/civil components within the scope of license renewal and subject to an AMR in Section 2.1 of the LRA. On the basis of this methodology, the applicant identified, in Table 2.4-5, the following emergency cooling tower and reservoir component groups as the passive and long-lived component groups subject to an AMR:

- reinforced concrete (walls, slabs, columns, beams, foundation, block walls)
- prestressed concrete (roof slab)
- structural steel (structural steel, reinforced concrete embedments)

The intended functions of the concrete components include providing (1) structural support, (2) fire barrier, (3) shelter, protection, and/or radiation shielding, (4) flood barrier, and (5) missile barrier. The structural steel components have a structural support intended function.

2.4.5.2 Staff Evaluation

The staff reviewed Section 2.4.5 of the LRA, Peach Bottom UFSAR Sections 10.24 and 12.2, relevant staff SERs, and the IPE and IPEEE to determine whether there is reasonable assurance that the emergency cooling tower and reservoir system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule.

Using the information provided in the LRA and the UFSAR, the staff sampled several components to determine whether the applicant properly identified the passive, long-lived structural components on the list of components subject to an AMR in Table 2.4-5 of the LRA. On the basis of the above review the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.4.5.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the emergency cooling tower and reservoir SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.4.6 Station Blackout Structure and Foundations

2.4.6.1 Summary of Technical Information in the Application

In Section 2.4.6 of the LRA, the applicant provided a description of the station blackout (SBO) structure. The SBO structure houses the switchgear necessary to connect the alternate AC source to the plant. The structure is a prefabricated steel enclosure with double doors at either end of the structure to facilitate equipment transfer in and out of the structure as required. The structure is designed to protect the equipment from damage due to external weather exposure and is mounted on three reinforced concrete piers. The license renewal drawing referenced for the SBO structure is LR-S-001.

The applicant determined that the following intended functions for the SBO structure and foundations fall within the scope of license renewal:

- Protection - The SBO structure protects equipment required for station blackout.
- Physical support - The SBO structure provides support for equipment required for station blackout.

In Section 2.1 of the LRA, the applicant described its process for identifying the structural/civil components falling within the scope of license renewal and subject to an AMR. On the basis of this methodology, the applicant identified, in Table 2.4-6 of the LRA, the following structural component groups subject to an AMR:

- reinforced concrete (foundation)
- structural steel (structural steel, reinforced concrete embedment, metal siding)

The concrete components have an intended function as structural support. The intended functions of the structural steel components are to provide (1) structural support and (2) shelter, protection, and/or radiation shielding.

2.4.6.2 Staff Evaluation

The staff reviewed Section 2.4.6 of the LRA, associated sections of the Peach Bottom UFSAR, relevant staff SERs, and the IPE and IPEEE to determine whether there is reasonable assurance that the SBO structure and foundation components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. On the basis of this review, the staff has made the findings described below.

In a letter dated March 22, 2002, the staff requested additional information on the SBO structure. Section 2.4.6 of the LRA stated that the SBO structure is a prefabricated steel enclosure with double doors at either end of the structure to facilitate equipment transfer in and out of the structure as required. The structure was designed to protect the equipment from damage due to external weather exposure. However, the LRA did not describe the structural components that protect the SBO equipment inside the enclosure from high wind, rainfall, and potential flooding. These components could include the materials for roof and wall sealing or moisture barriers, if any. If present, such materials should have been included in the scope of license renewal. In RAI 2.4.6-1, the staff requested that the applicant provide additional information on the components or commodities required for weather protection of the SBO structure.

In response to RAI 2.4.6-1 (in a letter dated May 22, 2002), the applicant stated that the SBO structure consists of an industrial-grade lineup of outdoor 13.8 KV and 34.5 KV metal-clad switchgear enclosures. The enclosure lineup is nominally 26 feet by 19 feet in plan, mounted on a steel skid that is supported on concrete piers. Each enclosure is constructed with 12 gage sheet metal and designed to operate in an outdoor environment. The SBO structure is classified as non-safety-related and was designed to commercial-grade standard. The structure is designed to protect the SBO equipment from rainfall and wind, but not resist high winds or flood.

The applicant stated that the enclosure is of welded steel construction, including the roof. Thus, the components, which provide the required protection, are included in Table 2.4-6 and Table 2.4-14 of the LRA. The joint between the switchgear enclosures forming the lineup is sealed with silicone sealant. The sealant is in the scope of license renewal and subject to an AMR. It is considered as a commodity and is included in the hazard barrier and elastomer commodity group identified in Table 2.4-14 of the LRA. The staff found the applicant's clarification in response to RAI 2.4.6-1 to be acceptable.

In review of the screening results of Section 2.5 of the LRA, the staff found that the applicant did not include any SBO-related structures or components within the scope of license renewal for the offsite power system. The function of the offsite power system under the SBO rule is to provide a means of recovering from the SBO. The system performs a function to demonstrate compliance with the NRC regulations on SBO that meets the criterion of 10 CFR 54.4(a)(3). In RAI 2.5-1, the staff asked the applicant to add the applicable structures and components of the offsite power system to the scope of license renewal.

In its response to RAI 2.5-1, the applicant, by letter dated May 22, 2002, supplemented its LRA to include additional structures and components of the offsite power system that should be included within the scope of license renewal and the AMR process. The offsite power system (substations and 13 Kv) consists of three power sources and their associated structures and components. The substations are designed to the industry standard for 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, and foundations and supports. The following structures and components protect and support the offsite power system:

- startup switchgear buildings
- substation control buildings
- switchgear enclosures
- manholes and ductbanks
- offsite power line poles

- raceway and switchgear supports
- supports for in-scope substation components
- cable trays, conduits, and electrical boxes

The structural components of the offsite power system that are subject to an AMR are the foundation, walls, block wall, slabs, ductbank, precast panels, structural steel, support members, offsite power line poles, metal siding, metal decking, anchors, reinforced concrete embedment, and electrical and instrument enclosures and raceways. The intended functions of these structural components are to provide (1) structural support, (2) shelter, and (3) protection and/or radiation shielding to the non-safety-related offsite power system and components.

The staff reviewed the RAI response and found that the applicant has properly identified the structures and components for the offsite power system that are within the scope of license renewal and subject to an AMR. The staff found applicant's response to RAI 2.5-1 to be acceptable because the structures and components that are within the scope of license renewal meet the requirements of 10 CFR 54.4 (a)(3) and the staff's SBO position in a letter dated April 1, 2002.

Based on the information provided in the LRA and additional information submitted by the applicant in response to the staff's RAIs, the staff sampled several components to determine whether the applicant properly identified the passive, long-lived structural components on the list of components subject to an AMR in Table 2.4-6 of the LRA. On the basis of the above review, the staff did not identify any omissions by the applicant.

2.4.6.3 Conclusions

On the basis of its review, the staff concludes that there is reasonable assurance that the applicant has adequately identified the SBO and offsite power system structures and their structural components that are within the scope of license renewal and subject to an AMR in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1), respectively.

2.4.7 Yard Structures

2.4.7.1 Summary of Technical Information in the Application

In LRA Section 2.4.7, "Yard Structures," the applicant describes the yard structures at the plant site, and identifies the structural components of the yard structures that are within the scope of license renewal and subject to an AMR. The general location of the yard structures is identified in drawing LR-S-001

In Section 2.1 of the LRA, the applicant described its process for identifying the structural/civil components within the scope of license renewal and subject to an AMR. Based on its methodology, the applicant, in Table 2.2-2, identifies the yard structures within the scope of license renewal and describes the results of its scoping methodology in Section 2.4.7 in the LRA.

The yard structures consist of various conduit duct banks, manholes, the high-pressure service water system valve pit, the service water pipe tunnel, and the condensate storage tank foundations. Conduit duct banks are located throughout the plant to provide passageways and protection for electrical cables and conduits. Manholes provide access to electrical components to meet accessibility requirements. These concrete structures provide a method for routing cables and provide protection from various environmental conditions. Manholes are protected from intrusion of combustible liquid by raised curbing or gaskets.

The high-pressure service water valve pit is a concrete structure located in the yard area south of the discharge outlet structure. Two high-pressure service water valves, as well as one emergency service water valve, are in the valve pit. The Unit 2 condensate storage tank is located south of the Unit 2 reactor building. Its base is supported on a 14-inch thick perimeter ring reinforced concrete wall and subbase consisting of crushed stone and sand. The Unit 3 condensate storage tank is located north of the Unit 3 reactor building. Its base is supported on the crushed stone and sand subbase. The high-pressure service water, service water, and emergency service water pipes run from the circulating water pump structure to the turbine building partially in the service water pipe tunnel.

The yard structures are further described in Section 6.3 of the Peach Bottom fire protection plan. The applicant's scoping methodology captures the yard structures within the scope of license renewal that meet the intent of 10 CFR 54.4(a) because they perform the following intended "structure level" functions:

- Physical support - The yard structures provide physical support for safety-and non-safety-related systems and equipment during normal, severe environmental, extreme environmental, and abnormal loading conditions.

- Protection - The yard structures provide protection for safety-related and non-safety-related systems and equipment from external, internal, and environmental hazards.

- Fire barrier – The yard structures provide rated fire barriers or retard a fire from spreading to adjacent areas of the plant.

On the basis of the above described methodology, the applicant identified the structures and structural components that are part of the yard structures. Table 2.4-7 lists the following structures and structural components that are subject to an AMR:

- reinforced concrete (walls, slabs, foundation)
- condensate storage tank foundations
- structural steel (reinforced concrete embedments for the service water pipe tunnel)

The intended functions of the concrete components include providing (1) structural support, (2) fire barrier, (3) shelter, protection, and/or radiation shielding, and (4) missile barrier. The structural steel components have a structural support intended function, as does the condensate storage tank foundation. As a result, the structures and structural components of the yard structures within the scope of license renewal perform their intended functions without moving parts or without change in configuration or properties, and are not subject to periodic replacement based on a qualified life or specified time period.

2.4.7.2 Staff Evaluation

The staff reviewed Section 2.4.7 in the LRA, the associated sections of the Peach Bottom UFSAR, the fire protection plan (FPP), relevant staff SERs, the IPE and IPEEE to determine whether there is reasonable assurance that the yard structures system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

Using the information provided in the LRA and the Peach Bottom UFSAR and FPP, the staff sampled several components identified in Table 2.4-7 of the LRA to determine whether the applicant properly identified the passive, long-lived structural components that were subject to an AMR. In a letter dated March 12, 2002, the staff requested additional information on the yard structure components subject to an AMR listed in Table 2.4-7 of the LRA. In RAI 2.4.7-1, the staff indicated that UFSAR Section 9.2 (page 9.3-4) stated that the water-tight dikes around the refueling water storage tank, the Unit 2 condensate storage tank, the Unit 3 condensate storage tank, and the torus water storage tank are seismically designed to withstand the effects of maximum ground acceleration due to the design basis earthquake. However, LRA Table 2.2-2 stated that the water-tight dikes did not fall within the scope of license renewal. The staff requested the applicant to provide justification for their exclusion.

In a letter dated May 22, 2002, in response to RAI 2.4.7-1, the applicant stated that the water-tight dikes around the refueling water storage tank, the condensate storage tanks, and the torus water storage tank were provided to contain any spills or overflow to support the liquid radwaste system design basis. The liquid radwaste system is designed such that discharge concentrations are always less than 10 CFR Part 20 limits. Water collected within the dikes is either directed to the radwaste system for processing or released to the plant storm drain system. Prior to any release to the storm drain system, the liquid is analyzed for radioactivity to ensure no significant radioactivity is released to the environment. The dikes are designed to withstand the effects of the maximum ground acceleration due to the design earthquake as indicated in UFSAR Section 9.2, but are not classified seismic Class I structures in the Peach Bottom UFSAR Appendix C.1.2, nor are they credited for a regulated event.

Based on the applicant’s response to the RAI, the staff reviewed the technical information in UFSAR Section 9.2. The staff found that the UFSAR Section 9.2.3, “Safety Design Basis,” states that the liquid radwaste system prevents the inadvertent release of significant quantities of liquid radioactive material from the site boundary of the plant which could result in radiation exposures to the public in excess of the limits specified in 10 CFR Part 100. UFSAR Section 9.2.9 states that leaks or spills from the liquid radwaste system are retained by secondary enclosures such as water-tight dikes and the water-tight dikes support the liquid radwaste system, by providing a barrier, in meeting its safety design of ensuring that a radioactive release to the public in excess of 10 CFR Part 100 limits is prevented. Therefore, this item was characterized as SER Open Item 2.4.7.2-1.

In a letter dated November 26, 2002, in response to Open Item 2.4.7.2-1, the applicant stated that the staff's review of UFSAR Sections 9.2.3 and 9.2.9 accurately reflect the content of the sections and is consistent with its review of the same UFSAR sections. However, the applicant questioned the accuracy of the UFSAR regarding the water-tight dikes and whether the water-tight dikes safety design basis met the requirements for being included within the scope of license renewal in accordance with 10 CFR 54.4. Consequently, the applicant performed a design basis review of the water-tight dikes to determine if they should be included within the scope of license renewal and subject to an AMR.

The PBAPS, Units 2 and 3, design, as stated in Appendix H of the UFSAR, satisfies the requirements of the 27 draft General Design Criteria for Nuclear Power Plants (November 1965) of the Atomic Energy Agency, and was later evaluated against the 70 criteria proposed in July 1967. Furthermore, the NRC staff's evaluation of the design bases for the liquid radwaste system is documented in Section 8.2 of the original facility safety evaluation, dated August 11, 1972. The staff's SER considered effluent activity, hydraulic model studies of the dipersion and dilution characteristics and concluded that liquid effluents are less than 10 CFR Part 20 limits. In addition, the water-tight dikes around the (1) refueling water storage tank and the Unit 2 condensate storage tank and (2) Unit 3 condensate storage tank are only seismically designed for the effects of maximum ground acceleration associated with the design earthquake. This design is consistent with requirements of Regulatory Guide 1.143, "Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light-Water Cooled Nuclear Power Plants."

Based on the above review, the applicant concluded that the "Safety Design Basis" of the liquid radwaste system is to prevent release of radioactive materials to the environment that exceed the limits of 10 CFR 20. The reference to 10 CFR 100 limits is inaccurate, since 10 CFR 20 limits are significantly lower than 10 CFR 100, and it follows that 10 CFR 100 limits will not be exceeded if 10 CFR 20 limits are not surpassed. As a result, the applicant revised UFSAR Section 9.2.3 to indicate that the liquid radwaste system prevents the inadvertent releases of radioactive material in excess of 10 CFR 20 limits, instead of 10 CFR 100 limits. The applicant provided a revised copy of UFSAR Section 9.2.3 as part of its November 26, 2002, response to Open Item 2.4.7.2-1.

Based upon the review of the original SER of 1972, and the applicant's safety evaluation of the water-tight dikes's design basis, the staff agrees with the applicant that the water-tight dikes were designed to meet 10 CFR 20 requirements. As such, the water-tight dikes do not meet the scoping criteria for 10 CFR 54.4 for inclusion within the scope of license renewal. Therefore, SER Open Item 2.4.7.2-1 is closed because the applicant's evaluation supporting the revision of UFSAR Section 9.2.3 demonstrates that the design of the water-tight dikes do not meet the requirements for being included within the scope of license renewal in accordance with 10 CFR 54.4.

On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.4.7.3 Conclusions

On the basis of its review the staff concludes there is reasonable assurance that the applicant has adequately identified the yard structures SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.4.8 Stack

2.4.8.1 Summary of Technical Information in the Application

In Section 2.4.8 of the LRA, the applicant provided a description of the Peach Bottom stack. A single stack is used to discharge gaseous waste from both units. The stack is located approximately 670 feet west of the reactor buildings, where the grade elevation is approximately 265 feet.

The stack is a tapered, reinforced concrete structure 500 feet high. The foundation is an octagonal concrete mat approximately 7 feet thick. The dilution fans and eductor are housed in the lower 30 feet of the structure. The stack is designed to seismic Class I criteria and for normal wind load; it is not designed to withstand tornado wind forces. The stack is located a sufficient distance from the reactor buildings so that they would not incur any damage in the event of a complete stack failure. The stack is discussed further in Section 12.2 and Appendix C of the Peach Bottom UFSAR. The license renewal drawing referenced for the stack is LR-S-001.

The only intended function within the scope of license renewal is elevated release. That is, the stack provides for the discharge of gaseous waste to meet the requirements of 10 CFR Part 100.

The applicant described its process for identifying the structural/civil components falling within the scope of license renewal and subject to an AMR in Section 2.1 of the LRA. On the basis of this methodology, the applicant identified, in Table 2.4-8, the reinforced concrete component group as the passive and long-lived component group subject to an AMR.

2.4.8.2 Staff Evaluation

The staff reviewed Section 2.4.8 of the LRA, Section 12.2 and Appendix C of the Peach Bottom UFSAR, relevant SERs, the IPE and IPEEE to determine whether there is reasonable assurance that the stack system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

In a letter dated March 12, 2002, the staff requested additional information on stack structure components subject to an AMR listed in Table 2.4-8 of the LRA. In RAI 2.4.8-1, the staff indicated that Section 2.4.8 of the LRA stated that the dilution fans and eductor are housed in the lower 30 feet of the stack structure. However, Table 2.4-8 did not contain supports or housings for this equipment. The staff inquired whether these components were within the scope of license renewal.

In a letter dated May 22, 2002, in response to RAI 2.4.8-1, the applicant stated that the dilution fans and eductor are components of the offgas and recombiner system, which is not within the scope of license renewal, as indicated in Table 2.2-1. Also, these components and their supports do not perform any intended function described by 10 CFR 54.4 and, consequently, they are not required to be referenced in the LRA tables. The staff found the applicant's clarification in response to RAI 2.4.8-1 to be acceptable.

Using the information provided in the LRA and the UFSAR, the staff sampled several components to determine whether the applicant properly identified the passive, long-lived structural components on the list of components subject to an AMR in Table 2.4-8 of the LRA. On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.4.8.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the stack SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.4.9 Nitrogen Storage Building

2.4.9.1 Summary of Technical Information in the Application

In Section 2.4.9 of the LRA, the applicant provided a description of the nitrogen storage building. The nitrogen storage building is a seismic Class I reinforced concrete structure (nominally 26.6 feet by 43.2 feet) founded on rock and structural lean-concrete backfill supported on rock. The western portion of the building is supported on and connected to the RHR pump room slab. The east wall is butted directly up to the Unit 2 condensate storage water dike wall. The north wall is structurally separated from the reactor building to eliminate interaction between both structures.

The license renewal drawing referenced for the nitrogen storage building is LR-S-001.

The applicant determined that the following intended functions for the nitrogen storage building fall within the scope of license renewal:

- Physical support - The nitrogen storage building provides physical support for safety-related and non-safety-related systems and equipment during normal, severe environmental, extreme environmental, and abnormal loading conditions.

- Protection - The nitrogen storage building provides protection for safety-related and non-safety-related systems and equipment from external, internal, and environmental hazards.

In Section 2.1 of the LRA, the applicant described its process for identifying the structural/civil components falling within the scope of license renewal and subject to an AMR. On the basis of this methodology, the applicant identified, in Table 2.4-9, the following component groups and the passive and long-lived components as subject to an AMR:

- reinforced concrete (walls, slabs, foundation)
- structural steel (reinforced concrete embedment)

The intended functions of the concrete components are to provide (1) structural support, (2) fire barrier, (3) shelter, protection, and/or radiation shielding, and (4) missile barrier. The structural steel components have a intended function of structural support.

2.4.9.2 Staff Evaluation

The staff reviewed Section 2.4.9 of the LRA, the associated sections of the Peach Bottom UFSAR, relevant staff's SERs, and the IPE and IPEEE to determine whether there is reasonable assurance that the nitrogen storage building system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule.

Based on the information provided in the LRA and the UFSAR, the staff sampled several components to determine whether the applicant properly identified the passive, long-lived structural components on the list of components subject to an AMR in Table 2.4-9 of the LRA. On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.4.9.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the nitrogen storage building SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.4.10 Diesel Generator Building

2.4.10.1 Summary of Technical Information in the Application

In the LRA, Section 2.4.10, "Diesel Generator Building," the applicant describes the structural components of the diesel generator building that are within the scope of license renewal and subject to an AMR. The general location of the diesel generator building is identified in drawing LR-S-001.

In Section 2.1 of the LRA, the applicant described its process for identifying the structural/civil components within the scope of license renewal and subject to an AMR. Based on its methodology the applicant, identified the diesel generator building within the scope of license renewal in LRA Table 2.2-2 and describes the results of its scoping methodology in Section 2.4.10.

Appendix C of the UFSAR states that seismic Class I structures are those whose failure could increase the severity of the design basis accident and cause release of radioactivity in excess of 10 CFR Part 100 limits and those essential for safe shutdown and removal of decay heat following a LOCA. Appendix C, Section C.1.2, identifies the diesel generator building as a Class I structure. This building is designed as a seismic Class I structure since it houses the four diesel generators which provide the standby power supply essential for safe shutdown of the plant upon loss of all offsite power. It has a fifth compartment that houses equipment required for operation of the emergency heat sink. The superstructure of the building consists of reinforced concrete walls and roof. Large openings in the diesel generator building are either protected by missile-proof doors or have baffle walls located in front of them. The emergency diesel fuel supply is stored in underground steel tanks east of the building. The applicant's scoping methodology captures the diesel generator building within the scope of license renewal since it meets the intent of 10 CFR 54.4(a), and the building performs the following intended "structure level" functions:

- Physical support - The diesel generator building provides physical support for safety-related and non-safety-related systems and equipment during normal, severe environmental, extreme environmental, and abnormal loading conditions.

- Protection - The diesel generator building provides protection for safety-related and non-safety-related systems and equipment from external, internal, and environmental hazards.

- Fire protection - The diesel generator building provides rated fire barriers or retards a fire from spreading to adjacent areas of the plant.

On the basis of the above described methodology, the applicant identified the structural components that are part of the diesel generator building. Table 2.4-10 lists the following component groups and structural components that are subject to an AMR:

- reinforced concrete (walls, slabs, columns, beams, foundation)
- structural steel (structural steel, reinforced concrete embedments)
- steel foundation piles

The intended functions of the concrete components include providing (1) structural support, (2) fire barrier, (3) shelter, protection, and/or radiation shielding, (4) flood barrier, and (5) missile barrier. The structural steel components and steel foundation piles have a structural support intended function. Therefore, the structural components of the diesel generator building within the scope of license renewal perform their intended functions without moving parts or without change in configuration or properties, and are not subject to periodic replacement based on a qualified life or specified time period.

2.4.10.2 Staff Evaluation

The staff reviewed Section 2.4.10 of the LRA, Section 12.2 and Appendix C of the Peach Bottom UFSAR, relevant staff SERs, the IPE and IPEEE to determine whether there is reasonable assurance that the diesel generator building system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

In a letter dated March 12, 2002, the staff requested additional information on diesel generator building structure components subject to an AMR listed in Table 2.4-10 of the LRA. In RAI 2.4.10-1, the staff indicated that Section 12.2.5 of the UFSAR stated that large openings in the diesel generator building are either protected by missile-proof doors, by baffle walls located in front of them, or by blowout panels. However, blowout panels were not mentioned in the LRA text or Table 2.4-10. The staff asked the applicant to indicate whether blowout panels and seals exist and whether they should be included in Table 2.4-10 or provide a justification for their exclusion.

The applicant responded to the staff's question in a letter to the NRC dated May 22, 2002. The applicant stated that blowout panels and blowout panel seals do not exist in the diesel generator building. Large openings in the building are protected either by missile-proof doors or by baffle walls located in front of them, but not blowout panels. This was confirmed by a detailed review of design drawings and a field walkdown of the building. The staff found the applicant's response to be acceptable.

In RAI 2.4.10-2, the staff indicated that Section 12.2.5 of the UFSAR stated that the superstructure of the building consisted of cast-in-place concrete walls and roof. The staff found that walls were included in Table 2.4-10 of the LRA. However, the roof was not explicitly addressed. The staff asked the applicant to clarify this.

The applicant, in its RAI response to the staff dated May 22, 2002, indicated that the roof of the diesel generator building consisted of a cast-in-place reinforced concrete slab. This structural component is included within the component group of reinforced concrete under slabs listed in Table 2.4-10. The staff found the applicant's response to RAI 2.4.10-2 to be acceptable.

The NRC staff reviewed the LRA, supporting information in the UFSAR, and the applicant's response to the staff's RAI. In addition, the staff sampled several components from Table 2.4-10 to determine whether the applicant properly identified the components that are within the scope of license renewal and subject to an AMR. On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.4.10.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the diesel generator building SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.4.11 Circulating Water Pump Structure

2.4.11.1 Summary of Technical Information in the Application

In Section 2.4.11 of the LRA, the applicant provided a description of the circulating water pump structure. The circulating water pump structure complex (nominally 280 feet by 80 feet) is a reinforced concrete structure with several sections founded on rock. The central portion is a seismic Class I reinforced concrete tornado-resistant structure. The central portion has three pump bays: one for Unit 2, one for Unit 3, and a third smaller bay which contains two emergency service water pumps in individual cells. These pump bays are interconnected by walls with openings equipped with sluice gates. The superstructure over these pumps has reinforced concrete walls and floor and a reinforced concrete roof supported on structural steel beams. Removable panels in the roof provide access to the pumps. A structural steel and plate wall divides the pump area into two rooms for additional protection. The rooms are flood-protected to an elevation of 135 feet by means of water-tight doors and sealed floor penetrations.

To the east of the superstructure is a similar seismic Class I reinforced concrete tornado-resistant structure which houses the service water traveling screens. Four screens, two per unit, are provided to screen the water before it goes into the pump bays. Each screen has a sluice-gated opening on each side.

The seismic Class I portion of the circulating water pump structure is designed such that no credible event, including internal flooding due to failure of a seismic Class II structure or component, would prevent the equipment housed therein from functioning as necessary to assure safe shutdown of both Units 2 and 3. The circulating water pump structure is further described in Section 12.2 of the UFSAR. The license renewal drawing referenced for the circulating water pump structure is LR-S-001.

The applicant determined that the following intended functions for the circulating water pump structure fall within the scope of license renewal:

- Physical support - The circulating water pump structure provides physical support for the safety-related and non-safety-related systems and equipment during normal, severe environmental, extreme environmental, and abnormal loading conditions.

- Protection - The circulating water pump structure provides protection for the safety-related and non-safety-related systems and equipment from external, internal, and environmental hazards.

- Fire protection - The circulating water pump structure provides rated fire barriers or retards a fire from spreading to the adjacent areas of the plant.

In Section 2.1 of the LRA, the applicant described its process for identifying the structural/civil components falling within the scope of license renewal and subject to an AMR. On the basis of this methodology, the applicant identified, in Table 2.4-11, the following component groups and the passive and long-lived structural components of the circulating water pump structure that are subject to an AMR:

- reinforced concrete (walls, slabs, columns, beams, foundation, block walls)
- structural steel (sluice gates and embedment, structural steel, reinforced concrete embedment)

The intended functions of the concrete components include providing (1) structural support, (2) fire barrier, (3) shelter, protection, and/or radiation shielding, (4) flood barrier, and (5) missile barrier. The structural steel components have the intended functions of structural support and flood barrier. The sluice gates and embedment have the intended function of maintaining pressure boundary.

2.4.11.2 Staff Evaluation

The staff reviewed Section 2.4.11 of the LRA, Section 12.2 of the Peach Bottom UFSAR, relevant staff SERs, and the IPE and IPEEE to determine whether there is reasonable assurance that the circulating water pump structure system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule.

Based on the information provided in the LRA and the UFSAR, the staff sampled several components to determine whether the applicant properly identified the passive, long-lived structural components subject to an AMR in Table 2.4-11 of the LRA. On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.4.11.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the circulating water pump structure SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.4.12 Recombiner Building

2.4.12.1 Summary of Technical Information in the Application

In Section 2.4.12 of the LRA, the applicant provided a description of the recombiner building. The recombiner building is a rectangular-shaped (nominally 66.5-feet-by-80.4 feet) reinforced concrete structure founded on rock that consists of several cubicle areas. It is a seismic Class I structure that houses the hydrogen recombiner system, catalytic recombiner, condensers, preheaters, analyzers, and other system equipment. This structure is located north of the Unit 3 reactor building and west of the Unit 3 turbine building. The structure has two exterior doors on the north wall at an elevation of 135 feet. The recombiner building is shared by Unit 2 and Unit 3 and houses their equipment.

The recombiner building is further described in Section 12.1 and Appendix C of the Peach Bottom UFSAR. The license renewal drawing referenced for the recombiner building is LR-S-001.

The applicant determined that the following intended function for the recombiner building falls within the scope of license renewal:

- Physical support - The recombiner building supports SSCs whose failure could adversely impact safety-related structures.

In Section 2.1 of the LRA, the applicant described its process for identifying the structural/civil components falling within the scope of license renewal and subject to an AMR. On the basis of this methodology, the applicant identified, in Table 2.4-12, the following component groups and the passive and long-lived structural components subject to an AMR:

- reinforced concrete (walls, slabs, columns, beams, foundation)
- structural steel

The reinforced concrete has the intended function of structural support, as does structural steel.

2.4.12.2 Staff Evaluation

The staff reviewed Section 2.4.12 of the LRA, Section 12.1 and Appendix C of the Peach Bottom UFSAR, relevant staff's SERs, and the IPE and IPEEE to determine whether there is reasonable assurance that the recombiner building system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

In a letter dated March 12, 2002, the staff requested additional information on the recombiner building components listed in Table 2.4-12 of the LRA. Section 12.1 and Appendix C of the UFSAR described the functions of the recombiner building, but did not describe the building structure. Table 2.4-12 of the LRA listed walls, slabs, columns, beams, and foundation as the components subject to an AMR. However, Table 2.4-12 did not list the building roof, nor did Section 2.4.12 of the LRA provide a justification for its exclusion. In RAI 2.4.12-1, the staff requested that the applicant verify the table to ensure its completeness or justify why the roof should not be within the scope of license renewal.

In response to RAI 2.4.12-1 (in a letter dated May 22, 2002), the applicant stated that the recombiner building is listed in Section 12.1 and Appendix C of the UFSAR as a seismic Class 1 structure, but, as the staff noted, it is not described in detail. The description provided in Section 2.4.12 of the LRA was extracted from the Peach Bottom structural Design Baseline Document. The structure is adjacent and communicates with the Unit 3 reactor building through the safety-related doors at elevation 165 ft. Major components of the building include reinforced concrete, concrete embedment, block walls, structural and miscellaneous steel, siding, and roofing material. The building does not house or support any safety-related systems, or equipment.

The applicant also stated that a detail review of the Peach Bottom CLB concluded that the building and its structural components do not perform an intended function pursuant to 10 CFR 54.4(a)(1) or (a)(3). However, as stated above, it is adjacent to the Unit 3 reactor building and its failure, although unlikely, may impact the safety of the reactor building structure. For this reason, the applicant has conservatively included the components critical to the building structural integrity in the scope of license renewal pursuant to 10 CFR 54.4(a)(2). These components are listed in Table 2.4-12 of the LRA and subject to an AMR as indicated in Table 3.5-12 of the LRA. Structural components, such as roofing, siding, decking, and internal partitions (block walls), do not contribute to the structural integrity of the recombiner building and their failure will not impact the reactor building. Therefore, they are not included in the scope of license renewal. The staff found the applicant's response to RAI 2.4.12-1 to be acceptable.

Based on the information provided in the LRA and the UFSAR, the staff sampled several components to determine whether the applicant properly identified the passive, long-lived structural components subject to an AMR in Table 2.4-12 of the LRA. On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.4.12.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the recombiner building SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.4.13 Component Supports

2.4.13.1 Summary of Technical Information in the Application

In Section 2.4.13 of the LRA, the applicant provided a description of the component supports. The component support commodity group includes the following component groups:

- support members
- anchors
- grout

The component group of support members include supports for piping and components, HVAC ducts, conduits, cable trays, instrumentation tubing trays, electrical junction and terminal boxes, electrical and I&C devices, and instrument tubing, and supports for major equipment, such as pumps, transformers, and HVAC fans and filters. This component group also includes components such as spring hangers, including the springs, rod hangers, braces, guides, clamps, base plates, metal-to-metal sliding joints, lubrite plates, snubber supports, stops, mounting brackets, support bolting, instrument racks, and bottle racks.

The component group, anchors, is the part of the component support assembly used to attach electrical panels, electrical cabinets, racks, switchgears, enclosures for electrical and instrumentation equipment, pipe hangers, pumps, transformers, HVAC fans, and HVAC filters to other components or structures. Welds are used for steel attachments while undercut anchors, expansion anchors, cast-in-place anchors, and grouted-in anchors are used for concrete attachments.

The component group of grout includes grouted support pads and grouted base plates. Grout is used in the construction of equipment pads and for filling, and leveling equipment bases and setting them to their respective foundations.

In Section 2.1 of the LRA, the applicant described its process for identifying the structural/civil components falling within the scope of license renewal and subject to an AMR.

In addition to the structures within the scope of license renewal presented in this section, the applicant also evaluated several structural component groups, such as component supports, as commodities. Commodity groups were determined based upon similar design or similar materials and similar environments. For each of the structural commodities, the applicant provided the following information: a general description of the commodity, a list of the components or component groups that require an AMR, and a list of associated component intended functions and environments.

On the basis of this methodology, the applicant identified, in Table 2.4-13, the following component groups as the passive and long-lived components subject to an AMR:

- support members
- anchors
- grout
- lubrite plates

All components in the component support commodity group have an intended function of structural support .

2.4.13.2 Staff Evaluation

The staff reviewed Section 2.4.13 of the LRA, the associated sections of the Peach Bottom UFSAR, relevant staff's SERs, and the IPE and IPEEE to determine whether there is reasonable assurance that the component supports system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components

having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

Section 2.4.13 of the LRA states that the component support commodity group includes support members, anchors, and grout. The staff found that bolts were used for the support members. However, bolts could also be used to fasten the components and structures that were not used for component support. For example, Section 5.2.3.4.7 of the UFSAR (page 5.2-9) mentioned bolts in relation to the drywell (vessel) head; Section 5.2.3.4.5 of the UFSAR (page 5.2-8) addressed bolted heads of the equipment hatches and bolted manways. In RAI 2.4.13-1 (in a letter dated March 12, 2002), the staff requested that the applicant clarify whether the bolts that are used to fasten structures for reasons other than for support are included in the component support commodity group.

In response to RAI 2.4.13-1 (in a letter dated May 22, 2002), the applicant explained that bolts for structures and structural components within the scope of license renewal are also in the scope of license renewal and subject to an AMR. The bolts are considered subcomponents of the structure or component they fasten and are evaluated as part of that structure or component. This is the case whether the bolts provide a structural support intended function or other functions such as the pressure-retaining function. For example, bolts for the drywell (vessel) head, bolts for equipment hatches, and bolts for manways are included in Table 2.4-1 of the LRA with their respective component group (drywell head, drywell equipment hatch, etc.). Their pressure boundary and structural support intended functions are enveloped by the intended function listed in the table for the drywell head, drywell equipment hatch, and other access hatches. The staff found the applicant's response to RAI 2.4.13-1 to be acceptable.

Based on the information provided in the LRA and the Peach Bottom UFSAR, the staff sampled several component supports to determine whether the applicant properly identified them in Table 2.4-13 of the LRA as being subject to an AMR. On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.4.13.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the component supports SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.4.14 Hazard Barriers and Elastomers

2.4.14.1 Summary of Technical Information in the Application

In Section 2.4.14 of the LRA, the applicant describes the hazard barrier and elastomer commodity group, which includes fire and other hazard barrier penetration seals, fire wraps, and fire and other hazard barrier doors.

Elastomer components include expansion joint seals (seismic joint seal material, control joint seal material, and seismic separation joint seal material), moisture barrier inside drywell at the juncture of the drywell shell wall with the concrete floor, reactor building blowout panel seals, and reactor building metal siding gap seals. Hazard barriers and elastomers are treated as a commodity because of similarities in design, material, aging effect, and/or environment. The steel components are treated as a commodity group because of similarities in design, material, and/or environment.

The applicant describes its process for identifying the structural/civil components falling within the scope of license renewal and subject to an AMR in Section 2.1 of the LRA. In addition to the structures within the scope of license renewal presented in this section, the applicant evaluated several structural component groups, such as hazard barriers and elastomers, as commodities. Commodity groups were determined on the basis of similar design or similar materials and similar environments. For each of the structural commodities, the applicant provides the following information:

- general description of the commodity
- list of the components or component groups that require aging management review and the associated component intended functions and environments

On the basis of this methodology, the applicant identifies the SSCs which form the hazard barrier and elastomer commodity group that are subject to an AMR in LRA Table 2.4-14. Table 2.4-14 lists fire barrier, flood barrier, HELB shielding, fission product barrier, shelter, protection, and/or radiation shielding, missile barrier, and overpressure protection as the intended functions of the hazard barrier and elastomer commodity group.

2.4.14.2 Staff Evaluation

The staff reviewed Section 2.4.14 of the LRA, the associated UFSAR sections, relevant staff SERs, the IPE and IPEEE to determine whether there is reasonable assurance that the hazard barrier and elastomer system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

In a letter dated March 12, 2002, the staff requested additional information regarding hazard barriers, and the applicant responded to that RAI in a letter dated May 22, 2002, as discussed below.

In RAI 2.3.3.7-3, the staff requested that the applicant identify, for each structure in LRA Section 2.4, if fire-resistive coatings have been applied to structural steel members serving as part of fire barriers and if they fall within the scope of license renewal and are subject to an AMR, or if fire-resistive coatings are present but not within the scope and not subject to an AMR, or provide a justification for their exclusion.

In a letter dated May 22, 2002, the applicant responded that fire-resistive coatings have been applied to structural steel beams on a limited basis in the reactor building, turbine building and main control room complex, radwaste building, and reactor auxiliary bay. The resistive coatings are within the scope of license renewal and subject to an AMR and, therefore, should be included in the scope of fire protection activities as described in LRA Appendix B.2.9.

Using the information provided in the LRA and the UFSAR, the staff sampled several cases of hazard barriers and elastomers to determine whether the applicant properly identified them as being subject to an AMR in Table 2.4-14 of the LRA. On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.4.14.3 Conclusion

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the hazard barrier and elastomer SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.4.15 Miscellaneous Steel

2.4.15.1 Summary of Technical Information in the Application

In Section 2.4.15 of the LRA, the applicant described the miscellaneous steel. The commodity group of miscellaneous steel includes platforms, grating, stairs, ladders, steel curbs, handrails, kick plates, instrument tubing trays, and manhole covers. These structural steel components are generally installed throughout Peach Bottom plant structures. Some structural steel components are exposed to the outdoor environment. These steel components are treated as commodities because of similarities in design, material, and/or environment.

In Section 2.1 of the LRA, the applicant described its process for identifying the structural/civil components falling within the scope of license renewal and subject to an AMR. In addition to the structures falling within the scope of license renewal presented in this section, the applicant evaluated several structural component groups such as miscellaneous steel, as commodities. Commodity groups were determined based upon similar design or similar materials and similar environments. For each of the structural commodities, the applicant provided the following information:

- a general description of the commodity
- list of the components or component groups that require an AMR, and the associated component intended functions and environments

On the basis of this methodology, the applicant identified, in Table 2.4-15, the structural components in the miscellaneous steel commodity group subject to an AMR. Table 2.4-15 of the LRA lists structural support, fluid containment, shelter, protection, and/or radiation shielding as the intended functions of the miscellaneous steel commodity group.

2.4.15.2 Staff Evaluation

The staff reviewed Section 2.4.15 of the LRA, the associated sections of the Peach Bottom UFSAR, relevant staff's SERs, and the IPE and IPEEE to determine whether there is reasonable assurance that the miscellaneous steel system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule.

Based on the information provided in the LRA and the Peach Bottom UFSAR, the staff sampled several kinds of miscellaneous steel components to determine whether the applicant properly identified them as being subject to an AMR in Table 2.4-15 of the LRA. On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.4.15.3 Conclusions

On the basis of this review, the staff concludes that there is reasonable assurance that the applicant has adequately identified the miscellaneous steel SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.4.16 Electrical and Instrumentation Enclosures and Raceways

2.4.16.1 Summary of Technical Information in the Application

In Section 2.4.16, "Electrical and Instrumentation Enclosures and Raceways," of the LRA, the applicant describes the structural components of the of the enclosures and raceways that are within the scope of license renewal and subject to an AMR. Additional information concerning SCs of the electrical and instrumentation enclosures and raceways is given in UFSAR Section 8.1, 7.1.6, "Redundant System Wiring Independence, Protection, and Marking", and the Peach Bottom Atomic Power Station Fire Protection Plan (FPP). The staff reviewed the electrical and instrumentation enclosures and raceways to determine whether there is reasonable assurance that the applicant has identified and listed structures and components subject to AMR in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1), respectively.

In Section 2.1 of the LRA, the applicant described its process for identifying the structural/civil components within the scope of license renewal and subject to an AMR. The electrical and instrumentation enclosures and raceways group at PBAPS includes cable trays, cable tray covers, drip shields, rigid and flexible electrical conduits and fittings, wireway gutters, panels, electrical panels, cabinets, and boxes installed in the reactor buildings and other PBAPS buildings. These electrical components are treated as a commodity group because of similarities in design, material, and environment.

The applicant identified component groups for the electrical and instrumentation and raceways that require AMR in Table 2.4-16 of the LRA. This table lists the component groups and component types, along with their passive functions and the component environments. The applicant has identified the following component groups for the electrical and instrumentation enclosures and raceways:

- electrical and instrumentation enclosures and raceways (cable tray and covers, electrical conduits and fittings, wireway gutters, panels, cabinets, and boxes)
- raceways (electrical conduits and fittings and boxes)
- drip shields

In Table 2.4-16 the applicant lists the SCs of the PBAPS electrical and instrumentation enclosures and raceways that are within the scope of license renewal because they fulfill one or more of the following intended functions:

- structural support
- shelter, protection, and/or radiation shielding

As a result, SCs of the electrical and instrumentation enclosures and raceways within the scope of license renewal perform their intended functions without moving parts or without a change in configuration or properties, and are not subject to periodic replacement based on a qualified life or specified time limit.

2.4.16.2 Staff Evaluation

The staff reviewed LRA Section 2.4.16, UFSAR sections 8.1, 7.1.6, and the FPP to determine whether there is reasonable assurance that the electrical and instrumentation enclosures and raceway components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

The staff reviewed the structural components in Table 2.4-16 to determine whether any other structures associated with the electrical and instrumentation enclosures and raceways meet the scoping criteria of 10 CFR 54.4(a) but were not included within the scope of license renewal. The staff then reviewed portions of the UFSAR descriptions to ensure that all SCs of the enclosures and raceways had been adequately identified and that they were passive and long-lived and performed their intended functions without moving parts or without a change in configuration or properties and were not subject to replacement based on a qualified life or specified time period. The staff found that cable tray and conduit supports, which perform a structural support intended function, were not included within the scope of license renewal in Table 2.4-16. However, cable trays and conduit supports were included within the scope of license renewal and are included in LRA Table 2.4-13, and are evaluated in Section 2.4.13 of this SER.

2.4.16.3 Conclusion

On the basis of its review, the staff concludes that there is reasonable assurance that the applicant has adequately identified the electrical and instrumentation enclosures and raceways SCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.4.17 Insulation

2.4.17.1 Summary of Technical Information in the Application

In Section 2.4.17 of the LRA, the applicant described the insulation commodity group, which 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 Peach Bottom plant areas that require temperature control include inside the drywell, inside the HPCI and RCIC pump rooms, the outboard MSIV rooms, on heat traced outdoor piping and components for freeze protection.

The jacketing on outdoor insulation applications has the function of maintaining leak-tightness by preventing the insulation material from absorbing moisture. Moisture not only decreases the effectiveness of the insulation, but also creates a corrosive environment in contact with the external piping or component surfaces. Piping and equipment insulation materials used inside the drywell include stainless steel and aluminum mirror insulation and fiberglass blanket insulation with either stainless steel or aluminum jacketing. HPCI and RCIC pump room and the outboard MSIV room piping insulation materials have calcium silicate or fiberglass blankets covered by an aluminum jacket. Equipment insulation consists of either calcium silicate blocks or removable ceramic fiber blankets. The antisweat insulation is fiberglass with an integral vapor barrier.

Outdoor piping insulation materials installed over electric heat tracing have calcium silicate or fiberglass with an integral vapor barrier with either a water-tight aluminum or a reinforced mastic-plastic compound jacketing.

The applicant described its process for identifying the structural/civil components falling within the scope of license renewal and subject to an AMR in Section 2.1 of the LRA. In addition to the structures falling within the scope of license renewal presented in this section, the applicant evaluated several structural component groups, such as insulation, as commodities. Commodity groups were determined on the basis of similar design or similar materials and similar environments. For each of the structural commodities, the applicant provided the following information:

- general description of the commodity

- list of the components or component groups that require an AMR, and the associated component intended functions and environments

On the basis of this methodology, the applicant identified the SSCs in the insulation commodity group that are subject to an AMR and listed them in Table 2.4-17 of the LRA . Table 2.4-17 of the LRA listed insulating characteristics and insulating jacket integrity as the intended functions of insulation commodity group components.

2.4.17.2 Staff Evaluation

The staff reviewed Section 2.4.17 of the LRA, the associated sections of the UFSAR, relevant staff SERs, the IPE and IPEEE documents to determine whether there is reasonable assurance that the insulation system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule.

Using the information provided in the LRA and the UFSAR, the staff sampled the insulation to determine whether the applicant properly identified insulation subject to an AMR in Table 2.4-17 of the LRA.

On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.4.17.3 Conclusions

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the insulation SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.5 Scoping and Screening Results: Electrical and Instrumentation and Controls

2.5.1 Summary of Technical Information in the Application

In Section 2.5, "Scoping and Screening Results: Electrical and Instrumentation and Controls," of the Peach Bottom Unit 2 and 3 LRA, the applicant describes the electrical components that are within the scope of license renewal and subject to an AMR. The staff reviewed this section of the LRA to determine whether there is a reasonable assurance that all SCCs within the scope of license renewal have been identified, as required by 10 CFR 54.4(a), and that all structures and components subject to an AMR have been identified, as required by 10 CFR 54.21(a)(1).

The applicant performed the screening for electrical/I&C components on a generic component commodity group basis for the in-scope electrical/I&C systems. The applicant used the guidance provided in NEI 95-10, Appendix B, to define electrical commodities subject to AMR. The guidance provided in NEI 95-10, Appendix B, identifies the following passive, long-lived electrical components as potentially subject to an aging management review:

- electrical portions of electrical and I&C penetration assemblies
- high-voltage insulators
- insulated cables and connections (connectors, splices, terminal blocks)
- phase bus (e.g., isolated-phase bus, non-segregated-phase bus, bus duct)
- switchyard bus

- transmission conductors
- uninsulated ground conductors

After applying the scoping and screening criteria as discussed in Sections 2.1.2 and 2.1.3 of the LRA, the applicant determined that the following Peach Bottom electrical commodities require an AMR:

- insulated cables and connections (connectors, splices, terminal blocks)
- electrical portions of electrical and I&C penetration assemblies

The electrical portions of electrical and I&C penetration assemblies are a TLAA and are addressed in Section 4.4 of the LRA.

The applicant also presents the scoping and screening results for station blackout systems. The applicant reviewed the components of the station blackout system and identified the passive, long-lived components subject to an AMR. The applicant defines the station blackout system as the alternate AC (AAC) source required per NUMARC 87-00, "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors." The station blackout system for PBAPS is in compliance with 10 CFR 50.63, qualifies as an AAC power source per NUMARC 87-00, and 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

2.5.2 Staff Evaluation

The staff reviewed Section 2.5 of the LRA and relevant sections of the Peach Bottom UFSAR to determine whether there is reasonable assurance that the electrical and instrumentation and control system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The staff also focused on components that were not identified as being within the scope of license renewal to determine if any components were omitted. The staff also sampled selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the rule. This was accomplished as described below.

The staff reviewed the design basis functions of each component type and the applicant's determination of which component types perform their functions without moving parts or a change in configuration or properties (passive and long-lived components) and therefore are subject to an AMR. The staff also reviewed the list of passive, long-lived electrical component types to determine which met the criteria of 10 CFR 54.4(a)(1) through (3). This step defined the set of electrical component types subject to AMR.

The following is a list of in-scope electrical component types subject to an AMR:

- insulated cables and connections (connectors, splices, terminal blocks)
- electrical portions of electrical and I&C penetration assemblies.
- Conowingo Hydroelectric Plant (Dam)
- Susquehanna substation
- wooden takeoff pole
- manholes at Conowingo and Peach Bottom
- submarine cable (transmission line)
- station blackout substation at PBAPS

Finally, the staff reviewed the information submitted by the applicant to verify that the applicant had not omitted or misclassified any electrical components requiring an AMR.

The list of in-scope electrical component types subject to an AMR does not include fuse holders. Fuse holders/blocks are classified as a 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. The applicant will include fuse holders in the connection category that requires an AMR. See Confirmatory Item Number 3.6.2.2.2-1 in Section 3.6.2.2.2 of this SER.

The screening results in Section 2.5 do not include any offsite power system structures or components. The license renewal rule, Section 10 CFR 54.4(a)(3), requires that "all systems, structures, and components relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission regulation for station blackout (10 CFR 50.63)" be included within the scope of license renewal. The station blackout rule, Section 10 CFR 50.63(a)(1), requires that each light-water-cooled power plant licensed to operate be able to withstand and recover from a station blackout of a specified duration (the coping duration) that is based upon factors that include "the expected frequency of loss of offsite power" and "the probable time needed to recover offsite power." Licensees' plant evaluations followed the guidance in NRC Regulatory Guide (RG) 1.155 and NUMARC 87-00 to determine their required plant-specific coping duration. The criteria specified in RG 1.155 to calculate a plant-specific coping duration were based upon the expected frequency of loss of offsite power and the probable time needed to restore offsite power, as well as the other two factors (onsite emergency AC power source redundancy and reliability) specified in 10 CFR 50.63(a)(1). In requiring that a plant's scoping duration be based on the probable time needed to restore offsite power, 10 CFR 50.63(a)(1) is specifying that the offsite power system be an assumed method of recovering from an SBO. Disregarding the offsite power system as a means of recovering from an SBO does not meet the requirements of the rule and results in a longer required coping duration. The function of the offsite power system under the SBO rule is, therefore, to provide a means of recovering from the SBO and the offsite power system thus this meets the criterion of 10 CFR 54.4(a)(3) as a system that performs a function that demonstrates compliance with the Commission's regulations on SBO. Based on this information, the staff asked the applicant to include applicable offsite power system structures and components within the scope of license renewal and subject to an AMR or provide additional justification for the system's exclusion.

The applicant responded in a letter dated May 22, 2002, that it will include those applicable offsite power system structures and components required to support the above description of "recovery" within the scope of license renewal and the AMR process, as described in the NRC letter to Alan Nelson and David Lochbaum, "Staff Guidance on Scoping of Equipment Relied on

To Meet the Requirements of the Station Blackout (SBO) rule (10 CFR 50.63) for License Renewal (10 CFR 54.4(a)(3)," dated April 1, 2002.

The offsite power system (substation and 13 kV) provides power to the 4kV safeguard busses via the 13 kV system. It consists of three power sources and their associated structures and components. The substation has the standard industry power distribution design and consists of switchyard bus, insulators, circuit breakers, ground and disconnect switches, transformers, offsite power line poles, and associated switchgear and control buildings, foundations, and supports. The offsite power system is discussed in UFSAR Section 8.1.

The applicant reviewed the electrical components of the offsite power system and identified the following passive, long-lived components as subject to an AMR:

- switchyard bus
- high-voltage insulators
- insulated cables and connections (connectors, splices, 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" power after an SBO event. The aging management review results for the electrical components are shown in Table 1 of the applicant's response dated May 22, 2002, to the staff's RAI. The following structures and components supports, which protect and support the offsite power system, are also included in the scope of license renewal and are subject to an AMR:

- startup switchgear buildings
- substation control buildings
- switchgear enclosures
- manholes and ductbanks
- offsite power line poles
- raceway and switchgear supports
- supports for in-scope substation components
- cable trays, conduits, and electrical boxes

The AMR results for the structural and component supports are shown in Table 2 of the response.

During a telephone conference on June 18, 2002, the staff requested the applicant to provide a detailed description of the PBAPS recovery path for offsite power from the power sources to the 4 kV emergency buses. In response to the staff request, in a letter dated July 30, 2002, applicant stated that the offsite power system consists of three independent power sources and their associated structures and components, which allow for power to be provided to the 4 kV emergency busses via the Substation and 13 kV Systems. The power sources come from the north substation, which is on a hill behind PBAPS. These power paths can be seen on license renewal drawing LR-E-1, with the exception of the #220-34 and the #1 autotransformer sources with their associated in-line load interrupter switch or disconnect switch. Additionally, the #220-08 line disconnect switch is not shown.

One power source is an overhead 230 kV transmission line (Graceton-Nottingham line #220-08) that brings power into the protected area boundary (PAB) via a transmission tower. The power line is then transitioned from the transmission tower to an outdoor substation bus bar structure. The power line continues to an in-line disconnect switch, goes through a 230 kV circuit breaker, and then connects to the 230/13.8 kV #2 startup and emergency auxiliary transformer. The 13.8 side of the transformer is then connected to the #2SU startup transformer switchgear bus via nonsegregated bus duct. The 13 kV system is then connected to the 13.2/4 kV #2 emergency auxiliary transformer via an underground duct bank, routed through manholes where required. The 4 kV side of the transformer is connected to the 4 kV emergency bus and switchgear via an underground duct bank into the plant.

The second source is an overhead/underground 230 kV transmission line (Peach Bottom-Newlinville line #220-34) entering the north substation and transitioning to an outdoor substation bus bar structure. It then goes through a 230 kV load interrupter switch and connects to the 230/13.8 kV #343 startup transformer. From the 13.8 kV side of the transformer, it goes through a 13 kV circuit breaker, and an in-line disconnect switch to another substation bus bar structure, and then transitions into an underground trench to the back of the substation. It then transitions via a substation bus bar structure to an overhead line, which goes down the hill into the PAB of the plant. The overhead line transitions to another substation bus bar structure, and then the line transitions to an underground duct bank, routed through manholes as required, into the #343 startup switchgear building and associated switchgear. The 13 kV line is then transitioned to the 13.2/4 kV #3 emergency auxiliary transformer via an underground duct bank, routed through manholes as required. The 4 kV side of the transformer is connected to the 4 kV emergency bus and switchgear via an underground duct bank into the plant.

The third source is a 13.8 kV source tapped off from the tertiary winding of the #1 auto transformer. From the tertiary winding the feed goes through a substation bus bar structure to an in-line disconnect switch and through a 13.8 kV circuit breaker to the #3 startup and emergency auxiliary regulating transformer. The feed then transitions to another substation bus bar structure, and then goes underground via a buried trench to a manhole at the back of the substation. From the manhole, the feed transitions via an outdoor cable tray to another manhole just outside the PAB. From there it transitions via an underground duct bank to the #3 SU regulating switchgear building and associated switchgear. The 13 kV feed transitions via a duct bank into the plant, where it connects to the 13 kV unit auxiliary buses and switchgear. Additionally, there is a 13 kV aerial tie between the switchgear in the #3 SU regulation switchgear building and the #343 SU transformer switchgear building.

The staff finds the applicant's response acceptable since it describes in detail the recovery power path for offsite power from the power sources to the 4kV emergency busses.

On the basis of the above review, the staff did not find any omissions by the applicant of SSCs within the scope of license renewal.

2.5.3 Conclusion

On the basis of its review, the staff concludes there is reasonable assurance that the applicant has adequately identified the electrical and instrumentation and control SSCs that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

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 July 2, 2014 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 required 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.

Appendix D of this SER is a list of commitments made by the applicant. Appendix D was developed by the applicant and verified by the staff. The list will be used in the staff's future confirmatory inspections of the applicant's programs associated with license renewal as a site-specific attachment to NRC Inspection Manual Inspection Procedure 71003, "Post Site Inspection for License Renewal." The list includes future inspection activity commitments, commitments to develop programs contingent on future staff actions, commitments to perform activities, such as calculations, that will be used to determine if further inspections are needed, commitments to implement and develop new programs depending on the outcomes of future inspection activities, and commitments to submit technical information.

3.0.1 Introduction

This section of the SER contains the staff's evaluation of the AMPs that are in Appendix B of the LRA, in responses to requests for additional information, in responses to open and confirmatory items, and in the annual update of the LRA. These AMPs are considered common AMPs because they are referenced as a part of the AMR results for two or more of the systems and/or structures. It should be noted that the staff's conclusions on the evaluations of these 22 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 auditable 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 B.1.1 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 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, and as supplemented in a letter from M.P. Gallagher to the NRC dated December 19, 2002 (the annual amendment to 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
- post accident sampling 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 Peach Bottom UFSAR. In addition, details of the reactor recirculation and post accident sampling systems are described on pages 19 and 21, respectively, of the applicant's letter dated November 26, 2002.

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), main steam, and post accident sampling 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 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 three times per week. 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 3.03.6.2-1 (see Sections 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 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 and RHR piping 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 B.1.3 of Appendix B of the LRA and as supplemented in a letter from M.P. Gallagher to NRC dated December 19, 2002. 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 B.1.3 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, EDG, and chilled water 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 components in the chilled water system, their intended functions, the associated environment, the materials of construction, and the aging effect are described on page 25 of Attachment 1 of the applicant's letter dated November 26, 2002.

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, and chilled water 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. The staff noted that the applicant did not verify the effectiveness of the CCW chemistry program through an inspection activity. This was identified as part of Open Item 3.0.3.6.2-1. By letter dated November 26, 2002, the applicant indicated that the inspections performed as part of the ISI program for ASME Class 2 piping would be credited to verify the effectiveness of the CCW chemistry program. The staff found the applicant's use of its ISI program, for license renewal, to verify the effectiveness of the CCW chemistry program acceptable because the ISI program at Peach Bottom includes inspections which are adequate to verify the effectiveness of the CCW chemistry program. Therefore, the staff considers Open Item 3.0.3.6.2-1 to be closed.

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 (9.0-10.4), nitrite (600-1200 ppm), and TTA (10-50 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 < 10ppm. The staff requested that the applicant confirm this information in writing. This was Confirmatory Item 3.0.3.3.2-1. By letter dated November 26, 2002, the applicant responded to

Confirmatory Item 3.03.3.2-1 by indicating that the acceptance criterion parameters for the chlorides and fluorides is < 10 ppm. These parameters are in accordance with the EPRI guidelines, and therefore acceptable to the staff. Therefore, the staff considers Confirmatory Item 3.0.3.3.2-1 to be closed.

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 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, condensate storage, and post accident sampling systems. 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, condensate storage, and post accident sampling 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 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, the staff noted that the applicant did not verify the effectiveness of the demineralized water and CST water chemistry program through an inspection activity. This was identified as part of Open Item 3.0.3.6.2-1. By letter dated November 26, 2002, the applicant indicated that the inspections performed as part of the ISI program for ASME Class 2 piping would be credited to verify the effectiveness of the demineralized water and CST chemistry program. The staff found that the applicant's use of its ISI program, for license renewal, to verify the effectiveness of the demineralized water and CST chemistry program is acceptable because the ISI program at Peach Bottom includes inspections which are adequate to verify effectiveness of the CST chemistry program. Therefore, the staff considers Open Item 3.0.3.6.2-1 to be closed.

Acceptance Criteria: The specific limits of demineralized water and CST water chemistry are conductivity ($\leq$ 1 µS/cm), chloride ($\leq$ 10 ppb), and sulfate ($\leq$ 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 B.1.5 of Appendix B of the LRA and as supplemented in a letter from M.P. Gallagher to NRC dated December 19, 2002. 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 B.1.5 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 unacceptable as discussed as part of Open Item 3.0.3.6.2-1 under the monitoring and trending program element because the staff noted that the applicant did not verify the effectiveness of the torus water chemistry program through an inspection activity.

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, the staff noted that the applicant did not verify the effectiveness of the torus water chemistry program through an inspection activity. This was identified as part of Open Item 3.0.3.6.2-1. By letter dated November 26, 2002, the applicant indicated that the inspections performed as part of the ISI program for ASME Class 2 piping would be credited to verify the effectiveness of the torus water chemistry program. The staff found that the applicant's use of its ISI program, for license renewal, to verify the effectiveness of the torus water chemistry program is acceptable because the ISI program at Peach Bottom includes inspections which are adequate to verify the effectiveness of the torus water chemistry program. Therefore, the staff considers Open Item 3.0.3.6.2-1 to be closed.

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 (≤ 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 (≤ 10 ppb), sulfates

(≤ 10 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 the UFSAR, 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 was identified as Open Item 3.0.3.6.2-1. In its response to Open Item 3.0.3.6.2-1, the applicant stated that in order to verify the effectiveness of the chemistry programs, inspections performed as part of the ISI program for ASME Class 2 piping in the HPCI, RCIC, RHR, and the core spray systems will be credited for PBAPS license renewal aging management. The applicant also indicated that the RWCU system is not included here because it is ASME Class 1 piping and is already committed in the ISI program in the LRA. The program scope of the ISI program was revised to incorporate these activities for license renewal. The staff found the applicant's use of its ISI program, for license renewal, to verify the effectiveness of the chemistry programs acceptable because the ISI program at Peach Bottom includes inspections which are adequate to verify the effectiveness. Therefore, the staff considers Open Item 3.0.3.6.2-1 to be closed.

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 ECW system piping and equipment support members 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 and pressure retaining wall thickness reduction when they are disassembled for maintenance
3. Visual inspection of susceptible ASME Class 1 values in the feedwater, RCIC, and HPCI systems for loss of material 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 (reactor water cleanup) systems
2. Visual inspection of ASME Class 1 valves and pumps in the reactor recirculation, RHR, core spray, and PCIS (reactor water cleanup) 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
5. Visual inspection of susceptible ASME Class 1 values in the feedwater, RCIC, and HPCI systems for loss of material when they are disassembled for maintenance
6. Visual inspection of susceptible ASME Class 1 reactor water cleanup system valves and reactor recirculation system pump casings to manage loss of fracture toughness through enhanced visual inspection to detect cracking before it reaches a critical size.

E. Borated Water

Monitoring of leakage during pressure test for management of loss of material and cracking for the SBLC system components from the suction side of the SBLC pumps to the RPV injection.

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 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 primary containment ISI 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 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 is in accordance with 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 pressure suppression 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 primary containment leakage rate testing 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 applicant's approach to monitoring and trending aging in components within the scope of the BWRVIP reports adequate because it is consistent with the staff approved BWRVIP programs.

Acceptance Criteria: BWRVIP I&E reports provide the basis for 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 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	the end of 2003	N/A
Nozzle safe ends and piping	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	ML003776110
Jet pump assemblies	BWRVIP-41	05/01/01	ML011310322
CRDH stub tubes and guide tubes, ICM housing guide tubes and penetrations	BWRVIP-47	12/07/00	ML003775765
Instrument penetrations	BWRVIP-49	03/31/02	NUDOCS A9153 241-253
Integrated Surveillance Program Plan	BWRVIP-78	02/01/02 (40 years)	ML020380691
Intergrated Surveillance Program: Implementation Plan	BWRVIP-86	02/01/02 (40 years)	ML020380691

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, which deals with cracking and inspections of the core shroud, has not been completed, PBAPS has indicated by letter dated May 6, 2002, that it will incorporate the NRC approved BWRVIP-76 programs into its aging management activities. 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 staff approved BWR core shroud inspection and flaw evaluation guideline program or a plant-specific program, and provide adequate revisions to the UFSAR Supplement summary description of the program.

The staff has completed the review of the integrated surveillance (ISP) program that is documented in BWRVIP-78 and BWRVIP-86. However, this program is only applicable for 40 years. The staff expects to receive a revised integrated surveillance program for review that is applicable for 60 years, which will be based on the technical criteria in BWRVIP-78 and BWRVIP-86.

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 & 86 is continuing. And while the proposed ISP addressed by BWRVIP-78 and BWRVIP-86 only applies for 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 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 staff approved ISP or a plant-specific ISP program, and provide adequate revisions to the UFSAR Supplement summary description of the ISP 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 experience 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 evaluation 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 A.2.7 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. 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 provide a 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 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 staff requested Confirmatory Item 3.0.3.11.2-1 that the applicant clarify the scope of the maintenance rule structural monitoring program. In its response, dated November 26, 2002, the applicant provided a complete revision of Appendix B.1.16, which is the description of the maintenance rule structural monitoring program. The applicant also updated the UFSAR Supplement for the maintenance rule structural monitoring program. The revised program scope states that the maintenance rule structural monitoring program provides for condition monitoring of reinforced concrete components masonry block walls, and grout in accessible areas. The revised USFAR Supplement for the maintenance rule structural monitoring program also includes the applicant's commitment to manage the aging of concrete and grout in accessible areas. In addition, the revised USFAR Supplement states that carbon steel structures and components are monitored for loss of material. The staff concludes that the applicant's revision of the maintenance rule structural monitoring program and USFAR Supplement adequately reflect the commitments made in response to RAIs 3.5-1 and 3.5-2. As such, Confirmatory Item 3.0.11.2-1 is closed.

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 staff requested in Open Item 3.0.3.11.2-1 that the applicant revise the parameters inspected for the maintenance rule structural monitoring program to include inspection of the concrete components, which credit this program, for cracking, loss of material, and change in material properties. In its response to Open Item 3.0.3.11.2-1, dated November 26, 2002, the applicant revised the program description for the maintenance rule structural monitoring. As part of this revision, the applicant updated the “parameters monitored or inspection” section to include the following items:

- Reinforced concrete components and masonry block walls, in accessible areas, for loss of materials, cracking, and evidence of a change in material properties due to leaching of calcium hydroxide;
- Grout, in accessible areas, for cracking.

With the above revision to the “parameters monitored or inspected” portion of the program description, the staff considers this portion of Open Item 3.0.3.11.2-1 to be closed.

For inaccessible concrete components, the staff has determined that aging management is unnecessary if the applicant is able to show that the soil/water 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 describe the provisions of the Maintenance Rule Structural Monitoring Program that ensure that the soil/water environment remains nonaggressive (e.g.) periodic sampling of groundwater). 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 staff requested in Open Item 3.0.3.11.2-1 that the applicant add additional acceptance criteria for the concrete components that now credit this program. In its response to Open Item 3.0.3.11.2-1, dated November 26, 2002, the applicant revised the program description for the maintenance rule structural monitoring. As part of this revision, the applicant updated the "parameters monitored or inspection" section to include the following items:

- Acceptance criteria for reinforced concrete components, masonry block walls, and grout are based on an evaluation of their 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.

With the above revision to the "parameters monitored or inspected" portion of the program description, the staff considers this portion of Open Item 3.0.3.11.2-1 to be closed.

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.1.16 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 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) 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.2.3 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.2.3 of the LRA of the to determine whether the applicant has demonstrated that the effects of aging will be adequately managed by the Ventilation System Inspection and Testing 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 9, 2002, the applicant indicated that the ECW pumps are inspected every 10 years The staff generated Confirmatory Item 3.0.3.13.2-1 to track the frequency of the ECW pump inspections and the frequency of RWST inspections, which is discussed below. In its November 26, 2002, response to Confirmatory Item 3.0.3.13.2-1, the applicant indicated that the ECW pumps are inspected every 10 years. This inspection frequency in combination with the ISI program inspections (as discussed in Section B.1.8 of the LRA) is acceptable to the staff to detect aging degradation of the ECW pumps; therefore, the staff considers this part of Confirmatory Item 3.0.3.13.2-1 to be closed.

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 9, 2002, the applicant indicated that the RWSTs are inspected every 4 years. The staff generated this part of Confirmatory Item 3.0.3.13.2-1 to track this item. In its November 26, 2002, response to Confirmatory Item 3.0.3.13.2-1, the applicant indicated that the RWSTs are inspected every 4 years. This inspection frequency in combination with the ISI program inspections (as discussed in Section B.1.8 of the LRA) is acceptable to the staff to detect aging degradation of the RWSTs; therefore, the staff considers this part of Confirmatory Item 3.0.3.13.2-1 to be closed.

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.

3.0.3.13.3 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).

3.0.3.13.4 Conclusions

The staff concludes that 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.2.6, 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 gaskets associated with the water tight 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 condition of hazard barrier doors will be monitored on a frequency consistent with the PBAPS Maintenance Rule Structural Monitoring Program.

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 staff noted that the summary description of the door inspection program provided in Section A.2.6 of Appendix A to the LRA did not reflect the applicant's commitment to monitor hazard barrier doors in a sheltered environment for loss of material due to corrosion. The staff identified this issue as Confirmatory Item 3.0.3.14.3-1. By letter dated November 26, 2002, the applicant included in the UFSAR description the commitment to monitor hazard doors in a sheltered environment. The staff considers Confirmatory Item 3.0.3.14.3-1 closed, and the staff finds the UFSAR Supplement acceptable.

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, 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 B.2.8 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 is 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.2.9 of the LRA to determine whether the applicant has demonstrated that the effects of aging will be adequately managed by the Fire Protection Activities 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 systems 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, fire dampers, 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 2.3.3.7 of the LRA.

Fire protection components that are subject to an aging management review include the pumps and valves (pressure boundary only), hose stations, 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, 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. Diesel driven fire pumps, fuel oil system pumps, valves, piping and flexible hoses are subject to an aging management review. 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 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 system 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 the LRA did not provide details regarding the inspection activities for the hose. This was identified as Open Item 3.0.3.16.2-1. By letter dated November 26, 2002, the applicant clarified that the hose will receive a visual inspection for change of material properties such as cracking, swelling, and hardening. The staff finds that the proposed inspections are acceptable because they will adequately detect the applicable aging effect. The staff considers Open Item 3.0.3.16.2-1 closed.

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

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 30,2002, 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.

By letter dated November 26, 2002, the responded to Open Item 3.0.3.16.2-1 by clarifying that the diesel-driven fire pump flexible hoses will receive a visual inspection for change of material properties such as cracking, swelling, and hardening. The staff finds that the visual inspection is adequate to detect the aging effects; therefore, the staff considers Open Item 3.0.3.16.2-1 to be closed.

The staff finds that the proposed inspections are reasonable and appropriate for detecting the identified aging effects; therefore, the staff finds this acceptable.

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 3.3-8, 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 because it 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.

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 1/4" 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 1/4"
- Verify that shrinkage of seal away from penetration surface (concrete or embedded sleeve) is less than 1/8" and no deeper than 1/4"

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 1/2"
- Verify shrinkage of the grout away from the penetration surface is less than 1/8" and no deeper than 1/2"
- 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 Rule 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.

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 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. 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 was part of Confirmatory Item 3.0.3.17.2-1. The staff requested that the applicant indicate what percentage of the subject heat exchangers are inspected. The staff generated Confirmatory Item 3.0.3.17.2-1 to track this item. The additional part of the confirmatory item is discussed below under the acceptance criteria program element. By letter dated November 26, 2002, the applicant indicated that all tubes of the HPCI gland seal condenser and the HPCI turbine lube oil cooler heat exhangers are visually inspected. The staff found the applicant's response acceptable and considers this part of Confirmatory Item 3.0.3.17.2-1 closed. 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.

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 all tubes of the HPCI gland seal condenser and the HPCI turbine lube oil cooler heat exchangers are visually inspected. This was part of Confirmatory Item 3.0.3.17.2-1.   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 was the other part of Confirmatory Item 3.0.3.17.2-1.The staff generated this second part of Confirmatory Item 3.0.3.17.2-1 to track this item. By letter dated November 26, 2002, the applicant indicated that the subject heat exchangers are very small heat exchangers and that all tubes are thoroughly cleaned and visually inspected. In addition, the applicant sited various inspection procedures that are used. The staff finds that these inspection procedures are adequate for detecting the identified aging effects; therefore, the staff considers this part of Confirmatory Item 3.0.3.17.2-1 closed.

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 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 annually. 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 appropriate.

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 B.2.4 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, annually.

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 B.1.13 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 one-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 piping inspection 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.3.4 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 B.1.4)) is used by PBAPS to manage loss of material and cracking in SBLC system 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 B3.4 of the LRA and in a letter from M.P. Gallagher to the NRC dated November 26, 2002. 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
- RPV instrumentation system
- reactor recirculation system
- fuel pool cooling system

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 was Confirmatory Item 3.0.3.19.2-1. The staff generated Confirmatory Item 3.0.3.19.2-1 to track this item. By letter dated November 26, 2002, the applicant indicated that this one-time inspection will occur before the end of plant life, between the years 30 to 40. The staff finds this acceptable and considers Confirmatory Item 3.0.3.29.2-1 closed.

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.3.4 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).

3.0.3.19.4 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 Peach Bottom Unit 2 and Unit 3 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 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 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 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 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 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 B.1.12 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. In a letter dated November 26, 2002, the applicant provided a revision to Section A.1.12 of the UFSAR Supplement. The revision indicates the PBABPS surveillance program will either be a plant-specific or an integrated surveillance program that meets that technical requirements in BWRVIP-78. This description is adequate since either program satisfies the requirements of 10 CFR Part 50, Appendix H.

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 (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).

3.0.3.22 Fuel Pool Chemistry Activities

The applicant described the fuel pool chemistry activities AMP in Section B.1.6 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).

3.0.3.22.1 Technical Information in the Application

In Section B.1.6 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 aluminum 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.”

3.0.3.22.2 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, aluminum, 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 to 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 pool 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 ($\leq$ 2 μS/cm), chlorides ($\leq$ 100 ppb), and sulfates ($\leq$ 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.

3.0.3.22.3 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 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).

3.0.3.22.4 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 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 stated that a new section, Section A.1.17, “Corrective Action Program,” would be added to describe the three attributes of interest. In a letter to the staff dated November 26, 2002, the applicant provided the new USFAR Supplement and it was renumbered from Section A.1.17 to A.1.13 in replacement of Standby Liquid Control System Surveillance Activities which was deleted as discussed in Section 3.3.4.2 of the SER. The staff reviewed the revised UFSAR Supplement and determined it adequately describes how the QAP addresses the three attributes of corrective actions, administrative controls, and confirmation process; therefore, the staff considers Confirmatory Item 3.0.4-1 closed,

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 that the applicant's UFSAR Supplement, as discussed above, (Appendix A of the LRA) 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). The staff also considers Confirmatory Item 3.0.4-1 closed.

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 in 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 Peach Bottom Units 2 and 3 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 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 System 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 stress corrosion cracking (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 was part of Open Item 3.1.3.2.1-1. In response to Open Item 3.1.3.2.1-1, by letter dated November 26, 2002, the applicant indicated PBAPS will manage the aging effect of cracking due to SCC for RPV instrumentation bolting by the Appendix B.1.8 Inservice Inspection program. In this program, inspection is performed in accordance with the ASME Code Section XI requirements. This program is acceptable to the staff because it will provide adequate inspection for detection of cracking due to SCC.

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 was part of Open Item 3.1.3.2.1-1. In response to Open Item 3.1.3.2.1-1, by letter dated November 26, 2002, the applicant indicates that a one-time inspection will be performed to confirm the effectiveness of the RCS chemistry program to mitigate the loss of material on the inside of carbon steel pipe. The one-time inspection will be performed to check the wall thickness of the carbon steel piping. One-Time Piping Inspection Activites are evaluated by the staff in SER section 3.0.3.19.2. The response is acceptable because checking wall thickness will confirm the effectiveness of the RCS chemistry program to mitigate the loss of material on the inside of carbon steel pipe.

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 was part of Open Item 3.1.3.2.1-1. In response to Open Item 3.1.3.2.1-1, by letter dated November 26, 2002, the applicant indicated PBAPS will manage the aging effect of loss of material for RPV instrumentation bolting by the Appendix B.1.8 Inservice Inspection program. In this program, inspection is performed in accordance with the ASME Code Section XI requirements. This program is acceptable to the staff because it will provide adequate inspection to detect loss of material in valve closure bolting.

<u>Loss of Preload</u>

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 was part of Open Item 3.1.3.2.1-1. In reponse to Open Item 3.1.3.2.1-1, by letter dated November 26, 2002, the applicant indicated PBAPS will manage the aging effect of loss of preload for RPV instrumentation bolting by the Appendix B.1.8 Inservice Inspection program. In this program inspection is performed in accordance with the ASME Code Section XI requirements. This program is acceptable to the staff because it will provide adequate inspection for detection of loss of preload.

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, 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 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

<u>Cracking</u>

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.

In response to Open Item 2.3.3.19.2-1 (provided in Section 2.3.3.19-2 of the SER), the applicant identified non-safety-related reactor recirculation system piping and valve bodies which fall within the scope of license renewal. These components are not subject to the Inservice Inspection (ISI) Program because they are not safety-related. These components are used in instrument lines which are exposed to reactor coolant. These lines are less than one inch in diameter, are installed without butt welds, are under reactor pressure, and are located beyond the excess flow check valves, which are designed to prevent gross leakage. These components are stainless steel and are identified as susceptible to cracking. The aging management program is the Reactor Water Chemistry Program. The Reactor Water Chemistry Program will mitigate cracking in stainless steel components, but will not monitor whether cracking is occurring. The staff requested that the applicant provide an inspection to determine whether the Reactor Water Chemistry Program is effective in preventing cracking. In response to the staff request, the applicant indicated that these lines are observed during hydrostatic pressure testing. Any leakage in these lines would be identified and corrective actions taken in accordance with the corrective action program. Therefore, any through wall cracks in these lines would be detected during the hydrostatic pressure test.

The Class 1 recirculation system components will be inspected to ASME Code Section XI requirements, which will be able to detect cracking. Since the Class 1 recirculation system components are fabricated from the same material and operate in the same reactor coolant water as the non-safety-related reactor recirculation components, the inspection results from the Class 1 components will be applicable to the non-safety-related reactor recirculation components and the inspection results from the Class 1 components will provide an effective program to monitor cracking for the non-safety-related reactor recirculation components. Thus the combination of the Reactor Water Chemistry Program, the inspection during hydrostatic pressure testing and the ASME Code Section XI inspection of Class 1 components will provide an acceptable program for managing cracking for the portion of the reactor recirculation system that was added to the scope of license renewal. By letter dated January 14, 2003, the applicant confirmed in a revised UFSAR Supplement that the Reactor Water Chemistry Program and the ASME Code Section XI inspection of Class 1 recirculation system components will be utilized to manage loss of material of non-safety-related reactor recirculation components.

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. In response to Open Item 3.1.3.2.1-1, by letter dated November 26, 2002, the applicant indicated PBAPS will manage the aging effect of cracking due to SCC for reactor recirculation system bolting in pumps and valves by the Appendix B.1.8 Inservice Inspection program. In this program inspection is performed in accordance with the ASME Code Section XI requirements. This program is acceptable to the staff because it will provide adequate inspection for detection of cracking due to SCC.

<u>Loss of Material</u>

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. In response to Open Item 3.1.3.2.1-1, the applicant indicated PBAPS will manage the aging effect of loss of material by wear for reactor recirculation system bolting in pumps and valves by the Appendix B.1.8 Inservice Inspection program. In this program inspection is performed in accordance with the ASME Code Section XI requirements. This program is acceptable to the staff because it will provide adequate inspection for detection of loss of material by wear.

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. In response to Open Item 3.1.3.2.1-1, by letter dated November 26, 2002, the applicant indicated PBAPS will manage the aging effect of loss of material by wear for reactor recirculation system bolting in pumps and valves by the Appendix B.1.8 Inservice Inspection program. In this program inspection is performed in accordance with the ASME Code Section XI requirements. This program is acceptable to the staff because it will provide adequate inspection for detection of loss of material by wear.

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, therefore it will not confirm the effectiveness of the RCS chemistry program to prevent loss of material in these components. In response to Open Item 3.1.3.2.1-1, by letter dated November 26, 2002, the applicant indicates that a one-time inspection will be performed to confirm the effectiveness of the RCS chemistry program to mitigate the loss of material on the inside of carbon steel pipe. The one-time inspection will be performed to check the wall thickness of the carbon steel piping. The One-Time Piping Inspection Activities are evaluated by the staff in SER section 3.0.3.19.2. The response is acceptable because checking wall thickness will confirm the effectiveness of the RCS chemistry program to mitigate the loss of material on the inside of carbon steel pipe.

In response to Open Item 2.3.3.19.2, the applicant identified non-safety-related reactor recirculation system piping and valve bodies which fall within the scope of license renewal. These components are not subject to the Inservice Inspection (ISI) Program because they are not safety related. These components are used in instrument lines which are exposed to reactor coolant. These lines are less than one inch in diameter, are installed without butt welds, are under reactor pressure, and are located beyond the excess flow check valves, which are designed to prevent gross leakage. These components are stainless steel and are identified as susceptible to loss of material. The aging management program is the Reactor Water Chemistry Program. The Reactor Water Chemistry Program will mitigate loss of material in stainless steel components, but will not monitor whether loss of material is occurring. The applicant indicates that these lines are observed during hydrostatic pressure testing. However, hydrostatic pressure testing will not detect loss of material unless it results in throughwall penetration.

The Class 1 recirculation system piping will be inspected to ASME Code Section XI requirements, which will be able to detect loss of material. Since the Class 1 recirculation system piping are fabricated from the same material and operate in the same reactor coolant water as the non-safety-related reactor recirculation piping, the inspection results from the Class 1 components will be applicable to the non-safety-related reactor recirculation piping and the inspection results from the Class 1 components will provide an effective program to monitor loss of material for the non-safety-related reactor recirculation piping. Thus the combination of Reactor Water Chemistry Program and the ASME Code Section XI inspection of Class 1 components will provide an acceptable program for managing loss of material for the portion of the reactor recirculation system that was added to the scope of license renewal. By letter dated January 14, 2003, the applicant confirmed in a revised UFSAR Supplement that the Reactor Water Chemistry Program and the ASME Code Section XI inspection of Class 1 recirculation system components will be utilized to manage loss of material of non-safety-related reactor recirculation components.

Cumulative Fatigue Damage

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. In response to Open Item 3.1.3.2.1-1, by letter dated November 26, 2002, the applicant indicated PBAPS will manage the aging effect of loss of preload for reactor recirculation system bolting pumps and valves by the Appendix B.1.8 Inservice Inspection program. In this program inspection is performed in accordance with the ASME Code Section XI requirements. This program is acceptable to the staff because it will provide adequate inspection for detection of loss of preload.

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 recirculation 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, the staff concludes that the applicant has demonstrated that these AMPs adequately manage the effects of aging associated with reactor recirculation 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, fittings, steam traps, rupture discs, spargers, restricting orifices, flow elements, and suction strainers), valve bodies, pump casings, filter bodies, turbine casing, flex hose, heat exchangers (HX) and their subcomponents (i.e., HPCI gland seals, coolers, coils, tubes, tubesheets, frames, channels, and shells), and vessels.

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

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.

<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 3.3-7, 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 3.3-7 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 HPCI 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. 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 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. In LRA Table 3.2-1(aging management results for HPCI 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 have adequately addressed the components whose aging effects can be managed by the application of the HPCI and RCIC turbine inspection activities.

Table 3.2.1 of the LRA indicates that the HPCI system contains flexible elastomer hoses subjected to an internal environment of lubricating oil and an external environment of "sheltered." LRA Section B.2.10 states that HPCI and RCIC Turbine Inspection Activities program will be enhanced to inspect the HPCI lubricating oil system flexible hoses for a change in material properties. In the applicant's April 29, 2002, response to RAI B.2.10-4, the applicant stated that the inspection of the HPCI lubricating oil system flexible hoses would be conducted every 8 years, concurrent with the inspections of the HPCI and RCIC turbine casings. The staff noted that inspections of similar items, such as the emergency diesel generator fuel oil flexible hoses, are conducted every 2 years. Therefore, the staff pursed additional information related to the types of inspections performed on the flexible hoses and justification. During a conference call on August 21, 2002, the applicant stated the HPCI lubricating oil system 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 hoses were gland seal bleed-off lines 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 staff generated Confirmatory Item 3.2.1.2.2-1 to track this item.

In its November 26, 2002, response to Confirmatory Item 3.2.1.2.2-1, the applicant stated that there are two types of flexible stainless steel hoses: one type exposed to a wetted gas internal environment and a sheltered external environment in the RCIC and HPCI systems, and one type exposed to an oil internal environment and a sheltered external environment in the HPCI system. As stated above, the staff finds that no aging management is required for the hoses with a wetted gas internal environment. The November 26, 2002, letter further states that the hoses with an oil internal environment will be managed by the Lubricating and Fuel Oil Testing Activities program. The Lubricating and Fuel Oil Testing Activities program, which is evaluated in 3.0.3.18 of this SER, relies, in part, on HPCI lube oil storage tank cleaning and inspection activities that are performed under the HPCI and RCIC Turbine Inspection Activities program to verify the effectiveness of the oil chemistry activities which will manage aging of the hoses. The staff agrees that Lubricating and Fuel Oil Testing Activities, evaluated in Section 3.0.3.18 of this SER, program will manage aging of the hoses because it was found to be adequate for managing aging of other stainless steel components in the same environment. The staff finds the applicant's response acceptable because there are no aging effects that need to be managed for the stainless steel hoses in a gas environment and for the hoses in the oil environment the aging effects will be managed; therefore, this Confirmatory Item 3.2.1.2.2-1 is closed.

The staff finds that the program scope is acceptable because it includes all components and aging effects that rely on the program.

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. This was part of Confirmatory Item 3.2.1.2.2-1. As discussed above, by letter dated November 26, 2002, the applicant explained that the flexible hoses are made of stainless steel and do not credit the HPCI and RCIC Turbine Inspection Activities program for aging management.

Based on the information provided in the LRA, the additional information provided in response to the RAIs, and the additional information provided in response to the 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.

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.

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.

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 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 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:

- demineralized water and 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 casings that are exposed to lubricating oil internally and sheltered air externally. The staff's evaluation of the surfaces of the cast iron casings 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 casings 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 CS 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 3.2.2, "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

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

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 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:

- Demineralized water and 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

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

In Table 3.2-4 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 low alloy steel turbine casing. 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 RCIC 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 RCIC 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, carbon/low-alloy steel materials (including galvanized carbon steel), 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) Radioactivity 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

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

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, carbon/low-alloy steel (including galvanized carbon steel), copper alloys (copper, bronze, or brass), or aluminum and are exposed to either condensate storage water, reactor coolant, of torus-grade water, 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 alloy 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) which 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, 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 RHR pump rooms. The staff evaluates these activities in Section 3.0.3.15 of this SER.

<u>High Pressure Service Water Radioactivity Monitoring Activities</u>

The applicant has credited the high-pressure service water (HPSW) radioactivity 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 B.1.7 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 B.1.7 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 B.1.7 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 A.1.7 of the UFSAR Supplement and found that the description of the applicant's HPSW radioactivity monitoring activities program is consistent with Section B.1.7

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 B.1.7 of the LRA and the summary description of the high pressure service water radioactivity monitoring activities in Section A.1.7 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

3.2.6.1 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, fittings, and vessels. 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

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

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, fittings, and vessels 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 SGTS 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. In addition, during a walkdown of the SGTS and a review of records for the SGTS, no aging concerns were identified (NRC inspection report 50-277/02-012, 50-278/02-012). Based on the staff's evaluation in Section 3.2.1.2.1 and the inspection results, 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 applicant identified that the SGTS also includes flex hoses made from neoprene or rubber. The applicant has identified loss of material properties as an applicable aging effect for SGTS flex hoses that are fabricated from neoprene or rubber and that are exposed to a gas environment. 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 agrees that loss of material properties is an applicable effect for the SGTS ESF components made from neoprene and rubber and concludes that the applicant's identification of aging effects for the SGTS neoprene materials is acceptable.

<u>Aging Effects for the Surfaces of SGTS Components Exposed to Soil Environments</u>

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

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

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, ESW 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. In a letter from M.P. Gallagher to the NRC dated November 26, 2002, responding to open and confirmatory items the applicant added additional systems to the scope. The applicant identified the following system groups 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, demineralized water and 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 chrome- 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 is in section 3.0.3.22

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.

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, 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 breakers 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 3.0.3.22.

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, 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:

- demineralized water and 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:

- demineralized water and condensate storage tank chemistry activities
- ISI activities

The demineralized water and 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 demineralized water and 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, 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 Section 3.0 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 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
- 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 this section and table 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 B.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 steel, and stainless steel.

A description of the environments is provided in Section 3.0 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 lube oil environments
- loss of material from carbon steel in buried environments
- heat transfer reduction of copper in raw water 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 table 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 steel, 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 motor oil cooler coils and 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 Section 3.0 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, or polyvinyl chloride 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, and supplemented by letters from M.P. Gallagher to NRC dated November 26, 2002, and January 14, 2003. 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 for 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
- Lubricating and Fuel Oil Quality Testing 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 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
- Lubricating and Fuel Oil Quality Testing Activities

The Fire Protection Activities, Outdoor, the Buried, and Submerged Component Inspection, and the Lubricating and Fuel 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, galvanized 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, carbon steel, 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, galvanized 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, carbon steel, 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, 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, bird screens, 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.

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, bird screens, 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, bird screens, 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, 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 environment, 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 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 atmospheric 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 2.3.3.14 and Table 3.3-14 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 casting and forging (valve bodies, pump casings), piping (pipe, tubing), and piping specialties (flow elements). These components are made of carbon steel, cast iron, alloy steel, and stainless steel.

A description of the environments is provided in Section 3.0 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, ISI 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 casting and forging (valve bodies), piping (pipe, tubing), and vessels (condensate storage tanks, tank nozzles). These components are made of carbon steel and stainless steel.

A description of the environments is provided in Section 3.0 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
- Demineralized Water and 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
- Demineralized Water and 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 Demineralized Water 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 offsite 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 and as supplemented in a letter from M.P. Gallagher to NRC dated December 19, 2002, 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, Teflon, copper, copper alloys, muntz metal, admiralty, 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 coolant 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, teflon, aluminum, aluminum alloys, stainless steel, neoprene and rubber, brass and brass alloys in the sheltered environment and no aging effects for carbon steel pipe in the outdoor environment, carbon steel strainer screens in the wetted gas environment and lube oil tank in the lubricating oil environments and stainless steel components in the outdoor environment. The applicant also identified no aging effects for Teflon in the closed cooling water, lubricating and fuel oil, and wetted gas environments. 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 loss of material in the 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
- Lubricating and Fuel 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
- Lubricating and Fuel Oil Quality Testing
- Emergency Diesel Generator Inspection
- GL 89-13 Activities

CCW Chemistry, Outdoor, Buried, and Submerged Component Inspection, Lubricating and Fuel 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.

<u>Emergency Diesel Generator Inspection AMP</u>

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 neoprene and rubber 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 neoprene and rubber 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 neoprene and rubber 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 neoprene and rubber 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 neoprene and rubber 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 neoprene and rubber 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 neoprene and rubber 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 neoprene and rubber flexible hoses. This procedure will be enhanced to include inspections of lubricating and fuel oil system neoprene and rubber 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 neoprene and rubber 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 neoprene and rubber 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 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 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 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 54.21(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 CFR 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 can 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 in a steam environment.

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 in a steam environment. 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 Sections 3.0.3.1, 3.0.3.2, and 3.0.3.6 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 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 required 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, low alloy, 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 and the changes to the LRA as supplemented in a letter from M.P. Gallagher to NRC dated December 19, 2002. 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, low alloy, and stainless steel in a sheltered environment—no aging effects
- carbon and low alloy steel and stainless in a reactor coolant environment—loss of material
- stainless steel in a reactor coolant environment—cracking
- low allow steel in a reactor coolant environment—loss of material

No aging effects were identified by the AMR for piping, piping specialties, tubing, and valve bodies made of stainless steel, low alloy 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, low alloy steel or carbon steel feedwater system components exposed to this environment.

Loss of material was identified for the carbon and stainless steel or low alloy steel piping, piping specialties, and valve bodies in a reactor coolant environment. Loss of material of carbon and stainless steel or low allow steel by corrosion may occur in reactor coolant environment, and therefore may be an applicable aging effect for the carbon steel or low alloy 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. The applicant will use the RCS chemistry program to manage loss of material for stainless steel or low alloy steel piping (tubing) 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 cracking 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 or low alloy steel piping, piping specialties, and valve bodies. The RCS chemistry program will be used to manage the cracking 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 Sections 3.0.3.1, 3.0.3.2, and 3.0.3.6 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 in 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 inaccessible concrete components, the staff has determined that aging management is unnecessary if applicants are able to show that the inaccessible 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 inaccessible reactor building concrete components, the staff has determined that aging management is unnecessary if applicants are able to show that the 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 concrete in inaccessible areas 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, concrete in inaccessible areas 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 B.2.2 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).

Fuel Pool Chemistry Program

The staff review of the fuel pool chemistry activities is in Section 3.0.3.22 of this SER.

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 2.5-1, 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 2.5-1 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 2.5-1 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 2.5-1 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 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 concrete in inaccessible areas 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, concrete in inaccessible areas 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 rock 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 driven 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 2.5-1 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 and 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 2.5-1 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 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 disagreed with the staff position, but it will use the Maintenance Rule Structural Monitoring Program or the ISI 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 filling and 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 x 10^{15} 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 (1) the component 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 (1) component 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. The applicant committed to monitor loss of material aging effect of galvanized carbon steel conduits in the outdoor environment using the PBAPS Fire Protection Activities (B.2.9). 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 (1) the component groups, (2) intended functions, (3) environments, (4) materials of construction, (5) aging effects, and (6) aging management programs.

Section 2.4.17 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 component 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-34.5kV 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.

- <u>PE Power and Control Cable Groups</u>

  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.

- <u>PVC Cable Groups</u>

  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.

- <u>Miscellaneous Cable Groups</u>

  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, and November 26, 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 Ethylene 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 wet or dry 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 was 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.

In response to the Open Item 3.6.1.2.1-1, the applicant, in a letter dated November 26, 2002, committed to an AMP to manage the aging of inaccessible medium-voltage cables not subject to 10 CFR 50.49 environmental qualification requirement.

The staff evaluated the proposed aging management activity for inaccessible medium-voltage cables not subject to 10 CFR 50.49 EQ requirements. 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's 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 activity applies to inaccessible (e.g., in conduit, duct bank, or direct buried) medium-voltage cables within the scope of license renewal (including 34.5 kV SBO alternate AC source) that are exposed to significant moisture simultaneously with significant voltage. Significant moisture is defined as periodic exposure to moisture that lasts more than a few days (e.g., cable in standing water). Periodic exposure to moisture that lasts less than a few days (i.e., normal rain and drain) not significant. Significant voltage exposure is defined as being subjected to system voltage for more than twenty-five percent of the time. The moisture and voltage exposures described as significant in these definitions, which are based on operating experience and engineering judgement, are not significant for medium-voltage cables that are designed for these conditions (e.g., continuous wetting and continuous energization is not significant for submarine cables). The staff found the scope of program acceptable because it includes inaccessible medium-voltage cables within the scope of license renewal that are exposed to significant moisture with significant voltage.

Preventive Action: This activity detects loss of conductor insulation material properties prior to loss of intended function for inaccessible medium-voltage cables, not subject to 10 CFR 50.49 environment qualification requirements. There are no preventive or mitigate attributes associated with this activity. The staff finds it acceptable because the applicant will test the inaccessible medium-voltage cables that are exposed to significant voltage and standing water and no preventive actions are necessary.

Parameter Monitored/Inspected: A representative sample of in-scope, medium-voltage cables exposed to significant moisture simultaneously with significant voltage are tested to provide an indication of the condition of the conductor insulation. The specific kind of test performed will be determined prior to the initial test and is to be a proven test for detecting deterioration of the insulation. Each test performed for a cable may be a different type of test. The staff requested the applicant to provide the basis of a sample selection of in-scope, medium-voltage cables to represent all inaccessible medium-voltage cable groups. In response to the staff's request, in a letter dated November 26, 2002, the applicant states that all cables within the scope of this program will be categorized into groups based on such factors as environment, type of routing (direct buried or buried ductbank), kV rating (4kV to 34.5 kV), and type of conductor insulation (e.g., EPR or XLPE). Of the cables in each of these cable groups, a representative sample of approximately 25% will be tested so that all cable groups are sampled. The staff found the applicant's response acceptable because the applicant provided a basis for sample selection that will represent all inaccessible medium-voltage cable groups

Detection of Aging Effects: In-scope, medium-voltage cables exposed to significant moisture simultaneously with significant voltage are tested at least one every 10 years. This is an adequate period to preclude failure 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 tests for license renewal are to be completed prior to the period of extended operation. The staff believes, based on current knowledge, that aging degradation of this cabling would be due to slow acting mechanisms. Therefore, the applicant's proposed test schedule is acceptable.

Monitoring and Trending: Trending actions are not required as part of this activity which is consistent with the GALL report. The applicant stated that the results not meeting acceptance criteria are entered into the corrective action program.

Acceptance Criteria: The acceptance criteria for each test are defined by the specific type of test performed and the specific cable tested. The staff finds such acceptance criteria acceptable as they will be based on current industry standards, which, when implemented, will ensure that the license renewal intended functions of the cables will be maintained consistent with the CLB.

Operating Experience: PBAPS has experienced several failure of XLPE cables due to water-treeing. A replacement program was initiated in 1995 to replace suspected cables with EPR cable, which is highly resistant to treeing. The replacement program was completed in 1999. No age related failures of the replaced cables have occurred. PBAPS and industry experiences support both the need for the program and the attributes of the applicant's program. Thus, the staff finds that operating experience is adequately incorporated into the development of this new program.

This program is similar to the GALL program, XI.E3. The staff found the applicant's response acceptable because the inaccessible medium-voltage cables exposed to significant moisture simultaneously with significant voltage are tested to provide an indication of the condition of the conductor insulation. The Open Item 3.6.1.2.1-1 is, therefore, closed.

FSAR Supplement:

In its November 26, 2002, response to Open Item 3.6.1.2.1-1, the applicant also included the summary description of the AMP that is to be added to the UFSAR as follows:

<u>A.3.5 INACCESSIBLE MEDIUM-VOLTAGE CABLES NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS</u>

In this aging management activity, in-scope, medium-voltage cables exposed to significant moisture simultaneously with significant voltage are tested to provide an indication of the condition of the conductor insulation. The specific test of test performed will be determined prior to the initial test. Each test performed for a cable may be a different type of test. This activity will provide reasonable assurance that aging effects on the conductor insulation are detected and addressed such that the intended function of these cable will be maintained for the period of extended operation. This activity will be implemented prior to the end of the initial operating license term for PBAPS.

The staff reviewed proposed Section B.3.5 of the UFSAR Supplement (Appendix B of the LRA) and verified 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 inaccessible medium-voltage cables not subject to 10 CFR 50.49 environmental qualification requirements 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).

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 has been revised (as indicated below) 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)

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. Exelon 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 PVC-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.

Monitoring 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.

Operating 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 was Confirmatory Item 3.6.1.2.2-1.

In response to the Confirmatory Item 3.6.1.2.2-1, in a letter dated November 26, 2002, the applicant included the following summary description of the AMP in the UFSAR Supplement:

A.3.3 Non-EQ Accessible Cable Aging Management Activity

The Non-EQ accessible cable aging management activity will visually inspect all cables and connections in accessible areas (easily approached and viewed) in the potential adverse localized environment. The Non-EQ accessible cable aging management activity will be performed once every ten years, beginning prior to the period of extended operation. This inspection activity will provide reasonable assurance that the intended function of electrical cables and connections that are not subject to environmental qualification requirements of 10 CFR 50.49 and are exposed to adverse localized environments caused by heat or radiation will be maintained consistent with the current licensing basis through the period of extended operation.

The staff found the response acceptable because it contains an adequate summary description of the program activities for managing the effects of the aging for the system and components as required by 10 CFR 54.21(d) and closed 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, 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 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 be 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 severe 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 was identified as Open Item 3.6.1.2.2-1.

In response to the staff Open Item, in a letter dated November 26, 2002, the applicant stated that at PBAPS, the drywell high range radiation monitoring system has General Atomic radiation monitors that are EQ and identified as subject to a TLAA in PBAPS LRA Section 4.4.1. The average power range monitor (APRM), local power range monitor (LPRM), and the wide range neutron monitor (WRMN) instrumentation circuits are the non-EQ portions of the neutron monitoring system within the scope of 10 CFR 54.4. The cables for the LPRMs were replaced in the late 1990s. WRNMs were installed in the late 1990s to replace the source range monitors and intermediate range monitors. The cables for these instrumentation circuits are routed in either flex or rigid conduit. There are no cables within the APRM instrument circuits that are in an adverse localized environment caused by heat or radiation. The APRM receives the neutron monitoring data from the LPRM detectors and cables. The applicant also states that it will commit to an aging management activity for the LPRM and the WRMN instrumentation cables not subject to 10 CFR 50.49 EQ requirements. The staff found the applicant's response acceptable because the applicant proposed an AMP in which a review of calibration results of surveillance activities are used to identify the potential existence of cable aging degradation. The Open Item 3.6.1.2.2-1 was therefore closed.

The staff evaluated the proposed aging management activity for electrical cables not subject to 10 CFR 50.49 EQ requirements used in instrumentation circuits as described above. 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 Activity: This program applies to electrical cables used in the LPRM and the WRMN instrumentation circuits. The staff found the scope of the program did not include the electrical cables used in high range radiator monitoring system and APRM instrumentation circuits. In the conference call dated November 7, 2002, the staff requested that the applicant explain why these cables were not included in the AMP. The applicant responded, in a letter dated November 26, 2002, that at PBAPS, the drywell high range radiator monitoring system has General Atomic radiator monitors and cables that are EQ and identified as subject to a TLLA in PBAPS LRA Section 4.4.1. There are no cables within the APRM instrument circuits that are in an adverse localized environment caused by heat or radiation. The APRM receives the neutron monitoring data from the LPRM detectors and cables. The staff found the applicant's response acceptable because it explains why high range radiator monitoring and APRM cables are not in scope of the AMP.   The staff also found the scope of the program acceptable because it includes all electrical cables used in nuclear instrumentation that are sensitive low-level signal that are subject to potentially adverse localized environment.

Preventive Actions: This is a surveillance activity. No actions are taken as part of this activity to prevent or mitigate aging degradation and the staff did not identify the need for such actions.

Parameters Monitor/Inspected: The parameters monitored are determined from the PBAPS technical specifications and are specific to the instrumentation circuit being calibrated, as documented in the surveillance activity. The staff found this approach to be acceptable because it provides means for monitoring the aging effects of the non-EQ electrical cables used in instrumentation circuits.

Detection of Aging Effect: Review of calibration results of surveillance activities can provide indication of the need for corrective actions by monitoring key parameters and providing data based on acceptance criteria related to instrumentation circuit performance. The normal calibration frequency specified in the PBAPS technical specifications provide reasonable assurance that severe aging degradation will be detected prior to the loss of the cable intended function. The staff found this acceptable on the basis that the calibration program identifies the need for corrective actions by monitoring key parameters and providing trending data based on acceptance criteria. The staff also found that the normal calibration frequency specified in the plant technical specifications provide reasonable assurance that aging degradation will be detected prior to loss of cable intended function.

Monitoring and Trending: Trending actions are not required as part of this activity which is consistent with the GALL report. The applicant stated that the results not meeting acceptance criteria are entered into the corrective action program.

Acceptance Criteria: The specific type of surveillance activity being performed and the specific instrumentation circuit being reviewed as set out in the PBAPS technical specifications defines the acceptance criterion for each review. The staff found the acceptance criteria acceptable because surveillance activity as set out in the plant technical specifications should ensure that cable intended functions used in instrumentation circuits are maintained under all CLB design condition during the period of extended operation.

Operating Experience: PBAPS has experienced degradation of cables in neutron monitoring systems. The cables for the LPRMs were replaced in the late 1990s. MRNMs were installed in the late 1990s to replace source range monitors and intermediate range monitors. The cables for these instrumentation circuits are run in either flex or rigid conduit. No age related failure resulting in loss of function for these cables has occurred since the cables were replaced. The staff found the proposed calibration program will detect the adverse localized environment of electrical cables used in instrumentation circuits.

UFSAR Supplement:

In response to the staff's open item, the applicant committed to include the following summary description in the UFSAR Supplement:

A.1.17 Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirement Used in Instrumentation Circuits

This aging management activity applies to electrical cables used in the Local Power Range Monitor and Wide Range Neutron Monitor Instrumentation circuits. The periodic review of calibration test results is used to identify the potential existence of aging degradation. When an instrument circuit is found to be significantly out of calibration, additional evaluation is performed on the circuit, including the cable, as required. This activity will provide reasonable assurance that the intended functions of electrical cables that are not subject to the environmental qualification requirements of 10 CFR 50.49 and are used in instrumentation circuits with sensitive, low-level signals exposed to adverse localized environments caused by heat, radiation, or moisture will be maintained consistent with the current licensing basis through the period of extended operation

The staff reviewed the proposed Section A.1.17 of the UFSAR Supplement (Appendix B of the LRA) and verified 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 Non-EQ electrical cables used in instrumentation circuits 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).

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 as well as additional information from the applicant. 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 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, April 29, and November 26, 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, 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 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 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 a 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 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. 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, and terminal blocks 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.

In a letter dated May 16, 2002, the NRC forwarded to the Nuclear Energy Institute (NEI) and Union of Concerned Scientists, a proposed interim staff guidance (ISG) for comment on screening of electrical fuse holders. The staff position indicated that fuse holders should be scoped, screened, and included in the aging management review (AMR) in the same manner as terminal blocks and other types of electrical connections that are currently being treated in the process. This position only applies to fuse holders that are not part of a larger assembly such as switchgear, power supplies, power inverters, battery chargers, circuit boards, etc. Fuse holders in these types of active components would be considered to be piece parts of the larger assembly and not subject to an AMR.

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 was Confirmatory Item 3.6.2.2.2-1.

In response to the staff confirmatory item, by letter dated November 26, 2002, the applicant stated that based on a conference call on September 5, 2002, and conference call on September 23, 2002, to clarify the basis for the Confirmatory Item, the applicant agreed with the above position that fuse holders are passive, long-lived electrical components within the scope of license renewal , and that only those fuse holders that are not part of a larger assembly are subject to an AMR. The applicant also agreed with the statement in the May 16, 2002 letter that, for the purpose of license renewal, fuse holders/blocks are classified as a specialized type of terminal block because of the similarity in design and construction.

Section 3.6.2, Table 3.6-2 of the LRA provides the aging management review results for connectors, splices, and terminal blocks based on environment and material of construction. Since fuse holders/blocks are classified as a specialized type of terminal blocks because of similarity of design and material of construction, it was the applicant’s position that there are no additional aging effects requiring management.

The staff disagreed with the applicant that there are no additional aging effects requiring management. The applicant revised Table 3.6-2 in the LRA to include the fuse holders in the Non-EQ Accessible Cable AMP. However, the AMP only address the insulation part but not the metallic parts (metallic clamps) of fuse holders. The AMP for fuse holders needs to include the following aging stressors: fatigue, mechanical stress, vibration, chemical contamination and corrosion on the metallic clamps of fuse holder. In addition, visual inspection alone may not be sufficient to detect the aging effects on the metallic clamps of the fuse holders. Therefore, the staff considered the fuse holder issue unresolved. This was considered Open Item 3.6.2.2.2-1.

In response to the Open Item, in the letter from M.P. Gallagher to the NRC dated January 14, 2003, the applicant provided a fuse inspection activity to manage the aging effects of the metallic portion of fuse holders. Subsequently, in a follow up conference call with the staff on January 27, 2003, the applicant decided to modify the aging management activity associated with the fuse holders. This was confirmed in two letters from M. P. Gallagher to NRC dated January 29 and 31, 2003. Appendix B.1.18, Fuse Inspection Activity, that was included in Attachment 2 of the January 14, 2003 letter was deleted and replaced with the following as documented in the January 29, 2003 letter:

B.3.6 Fuse Holder Aging Management Activity

Activity Description:

Staff guidance on the fuse holder issue has not been finalized at this time. When the fuse holder final guidance is issued by the NRC, Exelon will generate a new aging management activity to implement the requirements of the guidance.

UFSAR Supplement Appendix A.1.18, which was included in Attachment 2 of the January 14, 2003, was also deleted and replaced with the following:

A.3.6 Fuse Holder Aging Management Activity

After issuance of the final staff guidance regarding the aging management of fuse holders, a new aging management activity will be generated to implement the requirements of the final staff guidance. This activity will be implemented prior to the end of the initial operating license term for PBAPS.

The staff found the applicant’s response to Open Item 3.6.2.2.2-1 acceptable because the applicant committed to implement the final resolution of the ISG at the end of the initial license period for PBAPS; therefore Open Item 3.6.2.2.2-1 is closed.

3.6.2.3 Conclusions

The staff concludes that 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 is comprised 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

<u>Conwingo Hydroelectric Plant (Dam)</u>

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.

<u>Susquehanna Substation</u>

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.

<u>Wooden Pole</u>

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.

<u>Manholes</u>

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 in the emergency cooling tower and reservoir walls.

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 bar, 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 Hydroelectric 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 29, May 22, June 10, July 30, and November 26, 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 insulator 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.

During the staff visit to PBAPS on September 24 and 25, 2001, the staff questioned whether certain transitional cables within the scope of the SBO alternate AC source from the Conowingo hydroelectric plant to the PBAPS were inscope and subject to an AMR. The applicant agreed to a revised SBO system description that will include these cables and their aging effects. In a letter dated January 2, 2002, the applicant responded that:

> the original boundary for the cable (transmission line) and SBO components began at the output breaker in the Susquehanna Substation and went to the PBAPS Unit 2 start up bus 00A03C. The discussion in LRA Section 2.5.3 of the SBO alternate AC source did not specifically mention the cables spliced to the submarine cable, which occurs on land in the manholes both at Conowingo and PBAPS, nor did it specifically mention the cables from the Conowingo generator output breaker to the Susquehanna substation. These cables were considered to be bounded by the results of the Aging Management Review Technical Report for electrical cables, and were not specifically included in LRA Tables 2.5-1, 3.6-1, or 3.6-3 as a separate line item. The Cable Aging Management Review Technical Report for electrical cables used the "spaces" approach for assessing electrical cables based on insulation material and environment. The environments for the cable from the wooden pole to the manhole at Conowingo is a combination of "buried," and "outside"; the environment for the cable from the manhole at PBAPS to the SBO switchgear and Unit 2 Startup Bus 00A0C3 is "buried," and the environment for the cables from the Conowingo generators to the Susquehanna substation is a combination of "outdoor" and "sheltered." These environments are as defined in the LRA, Section 3.0. Table 3.6-3 of the LRA would be modified, due to above, to include the environment "buried" for these cables.

In addition, the applicant's response also stated that moisture was not an applicable aging effect for these cables. The staff disagreed with the applicant that moisture is not considered to be an applicable stressor for buried 35 kV cables spliced to the submarine cable. Medium-voltage cables exposed to wet conditions for which they are not designed can lead to "water treeing" which results in a decrease in the dielectric strength of the conductor insulation. This can potentially lead to electrical failure. Buried high-voltage cables are more susceptible to the "water treeing" phenomena. Therefore, the applicant had not provided a sufficient technical justification for not requiring an aging management program for inaccessible 35 kV cables and had 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 was part of Open Item 3.6.1.2.1-1.

In response to the staff's open item, the applicant agreed to include the 35 kV buried cables associated with SBO alternate AC source in the scope of the inaccessible medium-voltage cable AMP. This resolves the staff open item.

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 30, 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 was the other part of Open Item 3.6.1.2.1-1.

In response to this part of Open Item 3.6.1.2.1-1, the applicant agreed to include buried cables (4kV to 34.5 kV) associated with the offsite sources in the scope of the inaccessible medium-voltage cable AMP. This resolves the staff’s concern.

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 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 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 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).

<u>Susquehanna Substation Wooden Pole Inspection Activity</u>

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 Hydroelectric 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. Exelon 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 on 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 corporate 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 corporate 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 corporate and 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, 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).

4 TIME-LIMITED AGING ANALYSES

4.1 Identification of Time-Limited Aging Analyses

4.1.1 Introduction

The applicant describes its identification of time-limited aging analyses (TLAAs) in Section 4.1.1, "Identification of Time-Limited Aging Analyses," of the LRA. The staff reviewed this section of the LRA to determine whether the applicant has identified the TLAAs as required by 10 CFR 54.21(c) and described them in its UFSAR Supplement as required by 10 CFR 54.21(d).

In Section 4.1 of the application, the applicant described the requirements for the technical information to be reported in the application regarding time-limited aging analyses (TLAAs), as stated in 10 CFR 54.21(c). These include a list of TLAAs, as defined in 10 CFR 54.3, "Definitions," and a list of plant-specific exemptions granted pursuant to 10 CFR 50.12 that are based on TLAAs. The applicant also described the criteria used to identify TLAAs at Peach Bottom, Units 2 and 3. These criteria are the same as the six criteria stated in 10 CFR 54.3 for identifying TLAAs.

The identified TLAAs were evaluated and the results are described in Sections 4.1 through 4.7 of this SER. As required by 10 CFR 54.21(c), the applicant has provided a list of TLAAs in Table 4.1-1 of the LRA. The applicant also stated that no plant-specific exemptions based on TLAAs have been granted at Peach Bottom.

4.1.2 Summary of Technical Information in the Application

The applicant evaluates calculations for Peach Bottom against the six criteria specified in 10 CFR 54.3 to identify the TLAAs. The applicant identifies the following TLAAs:

- Reactor vessel neutron embrittlement
  - 10 CFR Part 50 Appendix G reactor vessel rapid failure propagation and brittle fracture considerations: Charpy upper shelf energy (USE) reduction and RT_{NDT} increase, reflood thermal shock analysis
  - Reactor vessel thermal limit analysis: operating pressure-temperature limit (P-T limit) curves
  - Reactor vessel circumferential weld examination relief
  - Reactor vessel axial weld failure probability

- Metal fatigue
  - Reactor vessel fatigue
  - Reactor vessel internals fatigue and embrittlement
  - Reactor vessel internals fatigue analyses
  - Reactor vessel internals embrittlement analyses
  - Effect of fatigue and embrittlement on end-of-life reflood thermal shock analysis

- Piping and component fatigue and thermal cycles
- Fatigue analyses of Group I primary system piping
- Assumed thermal cycle count for allowable secondary stress range reduction in Group II and III piping and components
- Design of the RHR system for a finite number of cycles
- Effects of reactor coolant environment on fatigue life of components and piping (Generic Safety Issue 190)

• Environmental qualification of electrical equipment
• Loss of prestress in concrete containment tendons not applicable
• Containment fatigue

- Fatigue analyses of containment boundaries: new loads analysis of torus, torus vents, and torus penetrations
- New loads fatigue analysis of SRV discharge lines and external torus-attached piping
- Expansion joint and bellows fatigue analyses (drywell-to-torus-vent bellows)
- Expansion joint and bellows fatigue analyses (containment penetration bellows)

• Other plant-specific TLAAs

- Reactor vessel corrosion allowances
- Generic Letter 81-11 crack growth analysis to demonstrate conformance to the intent of NUREG-0619
- Fracture mechanics of ISI-reportable indications for Group I piping: as-forged laminar tear in a Unit 3 main steam elbow

Pursuant to 10 CFR 50.21(c)(2), the applicant stated that no exemptions granted under 10 CFR 50.12 on the basis of a TLAA were identified. The applicant states that a technical alternative (as defined in 10 CFR 50.55a(a)(3)(i)) to requirements to inspect circumferential welds on the reactor pressure vessel has been approved by NRC. This TLAA is discussed in Section 4.2.3 of this SER.

In a separate licensing action, the applicant has submitted a license amendment for a power uprate to increase the maximum allowed operating power level. This power uprate is based on the increased accuracy of feedwater flow monitors. The higher power level may result in higher reactor coolant temperatures, increased reactor coolant flow, and/or increased neutron fluence. On July 23, 2002, the staff held a conference call with the applicant to ask if the the effects of the power uprate were considered during its evaluation of the TLAAs or that the analysis results are bounding for the higher power level. The applicant stated that the effects of the power uprate were considered. In response to Confirmatory Item 4.1.2-1, by letters dated November 26 and December 19, 2002, the applicant indicated that as part of the power uprate, a separate RPV fracture toughness evaluation was performed. The evaluation confirmed that the combined effects of license renewal and power uprate on fluence, adjusted reference temperature, and upper shelf energy at the end of the license renewal period are bounded by the values provided in the license renewal application Furthermore, no additional aging effects that require management are applicable due to the small increase in steam flow resulting from the power uprate. The applicant has adequately addressed the effects of the power uprate and license renewal by confirming the results of the power uprate and license extension are bounded by the results identified in the license renewal application.

4.1.3 Staff Evaluation

TLAAs are defined in 10 CFR 54.3 as analyses that meet the following six criteria:

- involve systems, structures, and components within the scope of license renewal, as delineated in 10 CFR 54.4(a)
- consider the effects of aging
- involve time-limited assumptions defined by the current operating term (for example, 40 years)
- were determined to be relevant by the applicant in making a safety determination
- involve conclusions or present the basis for conclusions related to the capability of the system, structure, or component to perform its intended functions, as delineated in 10 CFR 54.4(b)
- are contained or incorporated by reference in the CLB

In addition, to the TLAAs listed in Section 4.2 through 4.7 of the LRA, the staff identified three other potential TLAAs. The evaluation of these potential TLAAs is provided below.

<u>Flaw Growth Analyses</u>

Feedwater and Control Rod Drive Nozzles

Table 4.1-1 of the LRA identifies flaw growth analysis as a TLAA for feedwater nozzles and control rod drive return line nozzles. The table, however, does not identify the flaw growth analyses for other reactor coolant pressure boundary components as TLAAs. Flaws in Class 1 components that exceed the size of allowable flaws defined in IWB-3500 of the ASME Code need not be repaired if they are analytically evaluated to the criteria in IWB-3600 of the ASME Code. The analytic evaluation requires the applicant to project the amount of flaw growth due to fatigue or stress corrosion cracking mechanisms, or both where applicable, during a specified evaluation period. In RAI 4.1-1, the staff requested the applicant to identify all Class 1 components that have flaws exceeding the allowable flaw limits defined in IWB-3500 and that have been analytically evaluated to IWB-3600 of the ASME Code and submit the results of the analyses that indicate whether the flaws will satisfy the criteria in IWB-3600 for the period of extended operation. In response, the applicant stated that Exelon reviewed all preservice and inservice inspection summary reports as part of the effort to identify all potential TLAAs. Exelon reviewed all dispositions which might have included an IWB-3600 evaluation.

The only other flaw evaluated with time-dependent methods similar to IWB-3600 for the licensed operating period is a laminar indication in a Unit 3 main steam elbow (discussed in Section 4.7.3 of the LRA). This section describes the condition, the original fatigue calculation, and the basis for validating the calculation for the extended licensed operating period.

No other flaws evaluated with time-dependent methods similar to IWB-3600 extended to the end of the current licensed operating period. Since no other flaw evaluations met TLAA criteria, the staff find the applicant's response that such flaw evaluations were not TLAAs acceptable.

Pipe Break Locations

The applicant did not identify postulated pipe breaks locations based on the cumulative usage factor (CUF) as a TLAA for Peach Bottom. Although the applicant identified the fatigue usage factor calculation as a TLAA, the applicant did not identify the pipe break criteria as a TLAA. The usage factor calculation used to identify postulated pipe break locations meets the definition of a TLAA as specified in 10 CFR 54.3. In a teleconference on May 6, 2002, the staff requested the applicant to provide a description of the TLAA performed to address the pipe break criteria for Peach Bottom. In addition, the staff requested the applicant to identify any postulated pipe breaks locations based on CUF and describe the TLAA performed for these locations.

The applicant's June 10, 2002, response indicated that pipe breaks had been postulated at Peach Bottom locations where the CUF exceeds 0.1. The applicant also indicated that it did not expect the number of design transients assumed in these CUF calculations to be exceeded in 60 years of plant operation. Therefore, the CUF calculations which form the basis for the Peach Bottom pipe break postulations remain valid for the period of extended operation.

The Peach Bottom Unit 2 recirculation system piping was replaced in 1985-86 and the Unit 3 piping in 1988-89. The replacement was designed to ASME Section III Class 1 requirements. Peach Bottom UFSAR Appendix A.10.3.3 states that for the recirculation system piping, breaks have been assumed to occur at intermediate locations where the cumulative usage factor (CUF) exceeds 0.1. This piping was reanalyzed in 2001 to consider extended operation and no new breaks were identified. The analysis for extended operation used a piping life of 47 years for Unit 2 and 44 years for Unit 3, not 60 years, because the original piping has been replaced. The same screening criterion, 0.1 CUF, was used in all of the analyses. In addition, as identified in LRA Table 4.3.1-1, the reactor pressure vessel recirculation inlet and outlet nozzles and the residual heat removal system tee connections to the recirculation pipe are also included as monitoring locations in LRA Appendix B.4.2, "Fatigue Management Activities."

The applicant indicated that it did not expect the number of design transients assumed in these CUF calculations to be exceeded during the period of extended operation. Therefore, the Peach Bottom pipe break postulations remain valid for the period of extended operation in accordance with the requirements of 10 CFR 54.21(c)(1). The staff finds that the applicant's response is acceptable because the existing calculations are bounding for the period of extended operation. The staff concludes that the applicant has adequately evaluated the TLAA related to pipe breaks as required by 10 CFR 54.21(c). In the draft safety evaluation, the staff indicated that the UFSAR update needs to include a summary of the activities for the evaluation of this TLAA. This is was identified as Confirmatory Item 4.1.3-1.

The applicant's November 26, 2202, response to the open and confirmatory items referenced the CUF criteria in UFSAR Section A.10.3.3 used for postulating pipe breaks in the recirculation piping pipe breaks. The applicant also indicated that the reactor pressure vessel recirculation inlet and outlet nozzles and the RHR tee connections to the recirculation line are included in fatigue management program discussed in Section A.4.2 of the UFSAR Supplement. The staff finds that the applicant's UFSAR update contains an appropriate summary description of the activities to evaluate TLAAs related to fatigue as required by 10 CFR 54.21(d).

Crane Load Cycle Limit

In Section 4.1 of the LRA, the applicant did not identify a crane load cycle limit as a TLAA for the cranes within the scope of license renewal. Normally, based on the design code of the crane, a load cycle limit is specified at rated capacity over the crane's projected life. Therefore, it is generally necessary to perform a TLAA relating to crane load cycles estimated to occur up to the end of the extended period of operation.

By letter dated February 6, 2002, the staff requested additional information, per RAI 3.3-3, as to why the crane load cycle limit was not included as a TLAA. The applicant responded in a letter dated May, 6, 2002, in which it stated that it will update the UFSAR Supplement to include load cycles for the reactor building overhead bridge cranes, turbine hall cranes, emergency diesel generator bridges, and circulating water pump structure gantry crane as a TLAA in Section 4.7.4 of the LRA. In the response, the applicant stated that the cranes are predominantly used to lift loads which are significantly lower than the crane's rated load capacity. For example, the reactor building cranes will undergo less than 5000 load cycles in 60 years based on the projected number of lifts during refueling outages, handling of spent fuel storage casks, and testing. The other cranes are expected to experience significantly fewer load cycles than the reactor building cranes. Thus, the number of lifts at or near their rated load is low compared to the design limit of 20,000 load cycles. The applicant stated that the load cycles for these cranes were evaluated for the period of extended operation and it was determined that the analyses associated with crane design, including the load cycle limit, remain valid for the period of extended operation and, therefore, meet the requirements of 10 CFR 54.21(c)(1)(i). The staff agrees with the applicant's conclusion that the cranes will continue to perform their intended function throughout the period of extended operation as required by 10 CFR 54.21 (c)(1) and finds the applicant's response acceptable. The UFSAR Supplement needs to include a summary description of the evaluation of this TLAA ~~is~~ as required by 10 CFR 54.21(d). This was Confirmatory Item 4.1.3-2.

On November 26, 2002, the applicant provided the UFSAR Supplement. In Section A.5.7 of the UFSAR Supplement, the applicant provided a summary description of its evaluation of this TLAA for the period of extended operation. The description contains the basis for determining that the analyses associated with crane design, including the load cycle limit, remain valid for the period of extended operation and therefore, meet the requirements of 10 CFR 54.21(c)(1)(i). On the basis of its review of the information provided in Section A.5.7 of the UFSAR Supplement, the staff concludes that the applicant has provided adequate summary description of its evaluation of this TLAA for the period of extended operation as required by 10 CFR 54.21(d) and therefore, the confirmatory Item 4.1.3-2 is closed.

4.1.4 Conclusions

The staff has reviewed the information provided in Section 4.1 of the Peach Bottom LRA. The NRC staff concludes that the applicant has adequately identified the TLAAs as required by 10 CFR 54.21(c), and that no 10 CFR 50.12 exemptions have been granted on the basis of the TLAA as defined in 10 CFR 54.3. The staff also concludes that the applicant has adequately evaluated the TLAAs related to pipe breaks and the crane load cycle limit as required by 10 CFR 54.21 (c).

4.2 Reactor Vessel Neutron Embrittlement

4.2.1 10 CFR Part 50 Appendix G Reactor Vessel Rapid Failure Propagation and Brittle Fracture Considerations: Charpy Upper Shelf Energy (USE) Reduction and RT_{NDT} Increase, Reflood thermal shock analysis

4.2.1.1 Summary of Technical Information in the Application

The applicant described its evaluation of this TLAA in LRA Section 4.2, "Reactor Vessel Neutron Embrittlement."

Neutron Irradiation Embrittlement

Neutron irradiation causes a decrease in the Charpy upper shelf energy (USE) and an increase in the adjusted reference temperature (ART) of the reactor pressure vessel (RPV) beltline materials. The ART impacts the plant's pressure-temperature (P-T) limit and RPV integrity evaluations. BWRVIP-74 report contains integrity evaluations of the BWR RPV circumferentially oriented welds and the BWR RPV axially oriented welds. Therefore, in order to demonstrate that neutron embrittlement does not significantly impact BWR RPV integrity during the license renewal term, the applicant must determine the end-of-life fluence and the end-of-life RT_{NDT}, determine the validity of the reflood thermal shock analysis, and evaluate the impact of neutron irradiation on the Charpy USE reduction, P-T limits, RPV circumferential welds, and RPV axial welds.

Neutron Fluence and RT_{NDT}

The application does not contain the calculations for determining the end-of-life fluence and end-of-life RT_{NDT}. The application indicates that the applicant will initiate the calculations for end-of-life fluence using the GE fluence methodology after the NRC approves it. Then the applicant will recalculate the vessel end-of-life RT_{NDT} for a 60-year licensed operating life (54 EFPYs) according to Code Case N-640, "Alternative Reference Fracture Toughness for Development of P-T Limit Curves [ASME Code] Section XI, Division 1."

Reflood Thermal Shock Analysis

The applicant has reviewed the reflood thermal shock analysis for Peach Bottom. For the reflood thermal shock event, the peak stress intensity at 1/4 of vessel thickness from inside occurs at about 300 seconds after the LOCA. At 300 seconds, the analysis shows that the temperature of the vessel wall at a depth of 38.1 mm (1.5 inches) is approximately 204 °C (400 °F). The applicant expects that the vessel beltline material ART, even after 60 years of irradiation, will be low enough to ensure that the material is in the Charpy upper shelf region at 204 °C. Therefore, the analysis will be bounding and valid for the license renewal term.

Charpy Upper Shelf Energy (USE)

By letter dated April 30, 1993, the Boiling Water Reactor Owners Group (BWROG) submitted a topical report entitled "10 CFR Part 50 Appendix G Equivalent Margins Analysis for Low Upper Shelf Energy in BWR/2 Through BWR/6 Vessels," to demonstrate that BWR RPVs could meet margins of safety against fracture equivalent to those required by Appendix G of the ASME

Code Section XI for Charpy USE values less than 68 J (50 ft-lb). General Electric (GE) performed an update to the USE equivalent margins analysis, which is documented in EPRI TR-113596, “BWR Vessel and Internals Project BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines,” BWRVIP-74, September 1999. This updated analysis incorporates the effects of irradiation for 54 effective full-power years (EFPYs), which corresponds to 60 years of operation at 90% power. The updated analysis determined that the generic materials considered would maintain the margins for USE required by 10 CFR Part 50 Appendix G. The application indicates that the applicant plans to review the generic analyses with respect to their applicability for the Peach Bottom license renewal term. This review will determine whether the generic analyses are applicable and whether the critical materials would retain sufficient USE to satisfy 10 CFR Part 50 Appendix G requirements for 54 EFPYs. The applicant plans to complete this review and confirm the acceptable value for USE before the end of the initial operating license term for Peach Bottom.

4.2.1.2 Staff Evaluation

Neutron Irradiation Embrittlement

Appendix G to 10 CFR Part 50 specifies fracture toughness requirements for ferritic materials of the pressure-retaining components of the reactor coolant pressure boundary of light water nuclear power reactors to ensure adequate margins of safety during any condition of normal operation, including anticipated operational occurrences and system hydrostatic tests, to which the pressure boundary may be subjected over its service lifetime. For the RPV, this appendix requires an evaluation of the Charpy USE and an evaluation of the ART to determine pressure-temperature limits for the RPV. Neutron irradiation causes a decrease in the Charpy USE and an increase in the ART of the RPV beltline materials. The staff’s evaluation of the impact of irradiation on the reflood thermal shock analysis and Charpy USE is discussed in this section. The staff's evaluation of the impact of irradiation on pressure-temperature limit, RPV circumferential weld, and RPV axial weld integrity analyses is discussed in SER Sections 4.2.2.2, 4.2.3.2, and 4.2.4.2, respectively. Since each of these evaluations depends on the neutron fluence received by the RPV, neutron fluence is also discussed in these sections.

Neutron Fluence and RT_{NDT}

The RT_{NDT}, reflood thermal shock analysis, Charpy USE, P-T limit, circumferential weld, and axial weld integrity evaluations are all dependent upon the neutron fluence. The applicant states that it will initiate the calculations for end-of-life fluence for a 60-year licensed operating period (54 EFPYs) using the GE fluence calculation methodology (NEDC-32983P, "General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluation") after the NRC approves it.

In order to determine whether neutron irradiation embrittlement will satisfy the time-limited aging analysis criterion in 10 CFR Part 54.21(c)(1), the staff issued RAI 4.2-1 requesting the applicant to determine the adjusted reference temperature (ART) and the Charpy upper shelf energy (USE) at the end of the license renewal period (60 years of operation). These analyses require that the applicant determine the peak neutron fluence at the end of the license renewal period. Therefore, in RAI 4.2-1, the staff also requested the applicant to calculate the peak neutron fluence at the clad-steel interface and the 1/4 thickness (1/4T) location in the reactor vessels at the end of the license renewal period using a methodology approved by the staff and adhering to the guidance in Regulatory Guide (RG) 1.190,"Calculation and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence."

In response to RAI 4.2-1, the applicant submitted the following estimates of neutron fluence and adjusted reference temperature for Peach Bottom Units 2 and 3. The applicant response for estimates of upper shelf energy is presented later in this section under the heading Charpy upper shelf energy (USE).

Neutron fluence: For Units 2 and 3, the 54 EFPYs RPV peak fluence predictions are 2.2 x 10^{18} n/cm^2 at the inner vessel wall and 1.6 x 10^{18} n/cm^2 at 1/4T location. The neutron fluence calculation was performed using the methodology of NEDC-32983P, "General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluation," which was approved by the NRC in a letter dated September 14, 2001, from S.A. Richards (NRC) to J.F. Klapproth (GE). Since the neutron fluence evaluation was performed in accordance with a methodology that was approved by the staff, the results are acceptable and may be utilized for the evaluations discussed in SER Sections 4.2.2.2, 4.2.3.2, and 4.2.4.2.

The ART is defined as the sum of the initial (unirradiated) reference temperature (initial RT_{NDT}), the mean value of the adjustment in reference temperature caused by irradiation (delta RT_{NDT}), and a margin (M) term. The delta RT_{NDT} is a product of a chemistry factor and a fluence factor. The chemistry factor is dependent upon the amount of copper and nickel in the material and may be determined from tables in RG 1.99, Rev. 2, or from surveillance data. The fluence factor is dependent upon the neutron fluence at the maximum postulated flaw depth. The margin term is dependent upon whether the initial RT_{NDT} is a plant-specific or a generic value and whether the chemistry factor (CF) was determined using the tables in RG 1.99, Rev. 2, or surveillance data. The margin term is used to account for uncertainties in the values of the initial RT_{NDT}, the copper and nickel contents, the fluence, and the calculation methods. RG 1.99, Rev. 2, describes the methodology to be used in calculating the margin term.

The 54 EFPYs ART for the limiting beltline material for Unit 2 (Shell # 2 Heat C2873-1) at 1/4T is 70 °F. The 54 EFPYs ART for the limiting material for Unit 3 (Shell # 2, Heat C2773-2) at 1/4T is 97 °F. These values for ARTs were confirmed by the staff using the neutron fluence value of 1.6E18 n/cm^2, the initial RT_{NDT} values, and the Cu and Ni contents for the limiting beltline materials from the Peach Bottom Updated Final Safety Analysis Report, Volume 1. The Cu and Ni contents for the limiting beltline material are 0.12 and 0.57 wt%, respectively, for Unit 2, and 0.15 and 0.49 wt%, respectively, for Unit 3. The initial RT_{NDT} for the limiting beltline material is -6 °F for Unit 2 and 10 °F for Unit 3. A margin value of 34 °F was used for confirming the ARTs. The staff finds the ART consistent with RG 1.99, Revision 2, and acceptable.

Reflood Thermal Shock Analysis

The applicant has reviewed the reflood thermal shock analysis for Peach Bottom. For the reflood thermal shock event, the peak stress intensity at 1/4 of vessel thickness from inside occurs about 300 seconds after the LOCA. At 300 seconds, the analysis shows that the temperature of the vessel wall at a depth of 38.1mm (1.5 inches) is approximately 204 °C (400 °F). The applicant states that the reflood thermal shock analysis for 40-years of operation (32 EFPYs) will be bounding and valid for the license renewal term because the vessel beltline material ART, even after 60 years of irradiation, is expected to be low enough to ensure that the material is in the Charpy upper shelf region at 204 °C. In RAI 4.2-2, the staff requested the applicant to present the technical basis for expecting the vessel beltline material ART after 60 years of irradiation to be low enough so that the material is in the Charpy upper shelf region at 204 °C. In response, the applicant referred to its response to RAI 4.2-1, which indicated that the ART for the limiting plate material for Peach Bottom Unit 2 is 70 °F and for Unit 3 is 97 °F, which is well below the 204 °C (400 °F) 1/4T temperature predicted for the thermal shock event at the time of peak stress intensity. The reflood thermal shock analysis is, therefore, bounding and valid for the license renewal term.

Charpy Upper Shelf Energy (USE)

Section IV.A.1a of Appendix G to 10 CFR Part 50 requires, in part, that the RPV beltline materials have Charpy USE in the transverse direction for base metal and along the weld for weld material of no less than 50 ft-lb (68J), unless it is demonstrated in a manner approved by the Director, Office of Nuclear Reactor Regulation, that lower values of Charpy USE will ensure margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code.

By letter dated April 30, 1993, the Boiling Water Reactor Owners Group (BWROG) submitted a topical report entitled “10 CFR Part 50 Appendix G Equivalent Margins Analysis for Low Upper Shelf Energy in BWR/2 Through BWR/6 Vessels,” to demonstrate that BWR RPVs could meet margins of safety against fracture equivalent to those required by Appendix G of the ASME Code Section XI for Charpy USE values less than 50 ft-lb. In a letter dated December 8, 1993, the staff concluded that the topical report demonstrates that the evaluated materials have the margins of safety against fracture equivalent to Appendix G of ASME Code Section XI, in accordance with Appendix G of 10 CFR Part 50. In this report, the BWROG derived through statistical analysis the unirradiated USE values for materials that originally did not have documented unirradiated Charpy USE values. Using these statistically derived Charpy USE values, the BWROG predicted the end-of life (40 years of operation) USE values in accordance with RG 1.99, Rev. 2. According to this RG, the decrease in USE is dependent upon the amount of copper in the material and the neutron fluence predicted for the material. The BWROG analysis determined that the minimum allowable Charpy USE in the transverse direction for base metal and along the weld for weld metal was 35 ft-lb.

General Electric (GE) performed an update to the USE equivalent margins analysis, which is documented in EPRI TR-113596, “BWR Vessel and Internals Project BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines,” BWRVIP-74, September 1999. The staff review and approval of EPRI TR-113596 is documented in a letter from C. I. Grimes to C. Terry dated October 18, 2001. The analysis in EPRI TR-113596 determined the reduction in the unirradiated Charpy USE resulting from neutron radiation using the methodology in RG 1.99, Revision 2. Using this methodology and a correction factor of 65% for conversion of the longitudinal properties to transverse properties, the lowest irradiated Charpy USE at 54 EFPYs for all BWR/3-6 plates is projected to be 45 ft-lb. The correction factor for specimen orientation in plates is based on NRC Branch Technical position MTEB 5-2. Using the RG methodology, the lowest irradiated Charpy USE at 54 EFPY for BWR non-Linde 80 submerged arc welds is projected to be 43 ft-lb. EPRI TR-113596 indicates that the percent reduction in Charpy USE for the limiting BWR/3-6 beltline plates and BWR non-Linde 80 submerged arc welds are 23.5% and 39%, respectively. Since this is a generic analysis, the staff issued RAI 4.2-3 requesting the applicant to submit plant-specific information to demonstrate that the beltline materials of the Peach Bottom Units 2 and 3 RPVs meet the criteria in the report at the end of the license renewal period. The applicant was specifically requested to submit the information specified in Tables B-4 and B-5 of EPRI TR-113596. In response to RAI 4.2-3, the applicant stated that the predicted percent decrease of the beltline material USE values at 1/4T and 54 EFPYs was estimated using BWRVIP-74 and RG 1.99, Revision 2. The equivalent margin analysis was performed using information presented in Tables B-4 and B-5 of EPRI TR-113596. RG 1.99, Revision 2, predicted percent decrease in USE for the limiting beltline plate material at the end of the license renewal period is 14% for Unit 2 and 16% for Unit 3; both predicted values of USE are less than the generic value of 23.5% reported in EPRI TR-113596. Similarly, the RG 1.99, Revision 2, predicted percent decrease in USE for limiting weld material (non-Linde 80 weld material at both units) at the end of license renewal period is 21% for both Unit 2 and Unit 3, which is less than the generic value of 39% reported in EPRI TR-113596. The predicted values for the decrease in USE for limiting beltline weld and plate materials for Units 2 and 3 were confirmed by the staff using the 54 EFPYs neutron fluence values at 1/4T provided by the applicant and the values of the Cu contents for the limiting materials from the Peach Bottom Updated Final Safety Analysis Report, Volume 1. The 54 EFPYs neutron fluence at 1/4T for the limiting beltline plate and weld materials of both units is 1.6E18 n/cm^2. The Cu contents for the limiting beltline materials are 0.182 wt% for weld and 0.13 wt% for plate for Unit 2, and 0.182 wt% for weld and 0.15 wt% for plate for Unit 3. The staff finds the applicant response acceptable because the percent decrease in USE for plant-specific limiting plate and weld materials at Units 2 and 3 is bounded by the corresponding generic results obtained by the equivalent margin analysis presented in EPRI TR-113596 as mentioned above. Therefore, the Charpy USE values at 54 EFPYs for the limiting plate and weld materials at Units 2 and 3 are greater than the minimum allowable value of 35 ft-lb, which demonstrates that the evaluated materials have the margins of safety against fracture equivalent to Appendix G of Section XI of the ASME Code, in accordance with Appendix G of 10 CFR Part 50, throughout the license renewal period. The UFSAR Supplement needs to include the additional information contained in the applicant's response to RAI 4.2-3 regarding the evaluation of this TLAA. In a letter dated November 26, 2002, responding to this Confirmatory Item, the applicant provided a revision to Section A.5.1.1 of the UFSAR Supplement, which describes the USE analyses performed by the applicant, and adequately addresses the issue.

4.2.1.3 Conclusions

The staff has reviewed the information in LRA Section 4.2.1, "10 CFR 50 Appendix G Reactor Vessel Rapid Failure Propagation and Brittle Fracture Considerations: Charpy Upper Shelf Energy (USE) Reduction and RT_{NDT} Increase, Reflood Thermal Shock Analysis." On the basis of this review, the staff concludes that the applicant has adequately evaluated the TLAA related to 10 CFR Part 50 Appendix G reactor vessel rapid failure propagation and brittle fracture considerations (Charpy upper shelf energy (USE) reduction, RT_{NDT} increase, and reflood thermal shock analysis), as required by 10 CFR 54.21(c)(1)(i). The staff has also reviewed the UFSAR Supplement and the staff concludes that, the applicant has provided an adequate description of its evaluation of this TLAA for the period of extended operation as required by 10 CFR 54.21(d).

4.2.2 Reactor Vessel Thermal Analyses: Operating Pressure-Temperature Limit (P-T Limit) Curves

4.2.2.1 Summary of Technical Information in the Application

Peach Bottom Technical Specification 3.4.9 presents P-T limit curves for heatup and cooldown, and also limit the maximum rate of change of reactor coolant temperature. At Peach Bottom, the criticality curve presents limits for both heatup and criticality are calculated for a 40-year design (32 EFPY). The application indicates that the applicant will determine the P-T limits for 60 years (54 EFPY), in accordance with 10 CFR 54.21(c)(1)(ii), after the GE fluence methodology has been approved by the NRC.

4.2.2.2 Staff Evaluation

The P-T limit curves are based on the following NRC regulations and guidance: 10 CFR Part 50, Appendix G; Generic Letter (GL) 88-11, "NRC Position on Radiation Embrittlement of Reactor Vessel Materials and Its Impact on Plant Operations"; GL 92-01, "Reactor Vessel Structural Integrity, " Revision 1; GL 92-01, Revision 1, Supplement 1; RG 1.99, Revision 2; and Standard Review Plan (SRP) Section 5.3.2, "Pressure-Temperature Limits and Pressurized Thermal Shock." GL 88-11 advised applicants that the staff would use RG 1.99, Revision 2, to review P-T limit curves. RG 1.99, Revision 2, contains methodologies for determining the increase in transition temperature and the decrease in upper shelf energy resulting from neutron radiation. GL 92-01, Revision 1, requested that applicants submit their RPV data for their plants to the staff for review. GL 92-01, Revision 1, Supplement 1, requested that applicants submit and assess data from other applicants that could affect their RPV integrity evaluations. These data are used by the staff as the basis for the staff's review of P-T limit curves. Appendix G to 10 CFR Part 50 requires that P-T limit curves for the RPV be at least as conservative as those obtained by the methodology of Appendix G Section XI of the ASME Code.

SRP Section 5.3.2 presents an acceptable method of determining the P-T limit curves for ferritic materials in the beltline of the RPV based on the linear elastic fracture mechanics (LEFM) methodology of Appendix G to Section XI of the ASME Code. The basic parameter of this methodology is the stress intensity factor K_I, which is a function of the stress state and flaw configuration. Appendix G requires a safety factor of 2.0 on stress intensities resulting from reactor pressure during normal and transient operating conditions and a safety factor of 1.5 for hydrostatic testing curves. The methods of Appendix G postulate the existence of a sharp surface flaw in the RPV that is normal to the direction of the maximum stress. This flaw is postulated to have a depth that is equal to 1/4 the thickness (1/4T) of the RPV beltline thickness and a length equal to 1.5 times the RPV beltline thickness. The critical locations in the RPV beltline region for calculating cooldown and heatup P-T limit curves are the 1/4T and 3/4 thickness (3/4T) locations, which correspond to the maximum depth of the postulated inside surface and outside surface defects, respectively. The ASME Code Appendix G methodology requires that applicants determine the ART at the end of the operating period.

The applicant plans to calculate vessel P-T limit curves for 60 years (54 EFPYs) after the NRC has approved GE fluence calculation methodology. As discussed in Section 4.2.1.2 of the SE, the staff has approved the GE fluence calculation methodology that is documented in topical report NEDC-32983P, "General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluation." This topical report was approved by the NRC in a letter dated September 14, 2001 from S.A. Richards (NRC) to J.F. Klapproth (GE). In RAI 4.2-5, the staff requested the applicant to submit P-T limit curves for a 60-year (54 EFPYs) design for Peach Bottom using the GE methodology. In response, the applicant stated that the vessel P-T limit curves for 54 EFPYs have been completed. The plant technical specifications will be modified to incorporate these P-T limit curves when the current curves reach their operational limits. The curves will be submitted to the NRC as a license amendment prior to the end of the initial operating license term for Peach Bottom. The staff finds the applicant's response acceptable because the change in P-T curves will be implemented by the license amendment process.

4.2.2.3 Conclusions

The staff has reviewed the information in LRA Section 4.2.2, "Reactor Vessel Thermal Limit Analyses: Operating Pressure-Temperature Limit (P-T Limit) Curves." On the basis of this review, the staff concludes that the applicant has adequately evaluated the reactor vessel operating pressure-temperature limit curves TLAA, as required by 10 CFR 54.21(c)(1). The staff has also reviewed the UFSAR Supplement and the staff concludes the applicant has provided an adequate description of its evaluation of this TLAA for the period of extended operation as required by 10 CFR 54.21(d).

4.2.3 Reactor Vessel Circumferential Weld Examination Relief

4.2.3.1 Summary of Technical Information in the Application

Sections 4.2.3 and A.5.1.2 of the LRA discuss inspection of the Peach Bottom RPV circumferential welds. These sections of the LRA indicate that Peach Bottom will use an approved technical alternative in lieu of ultrasonic testing of RPV circumferential shell welds. The BWRVIP presented the technical bases in EPRI TR-113596 for supporting the elimination of RPV circumferential welds from the inservice inspection programs for BWRs. These technical bases are approved for the current license term and are applicable to Peach Bottom.

Appendix E of the NRC's safety evaluation report (SER), "Final Safety Evaluation of the BWR Vessel and Internals Project BWRVIP-05 Report " USNRC, July 28, 1998, documents an evaluation of the impact of license renewal from 32 to 64 EFPYs on the conditional probability of vessel failure. The SER reports that the frequency of cold overpressurization events results in a total vessel failure probability of approximately 5×10^{-7}. The SER conservatively evaluates an operating period of 10 EFPYs greater than what is realistically expected for a 20-year license renewal term, i.e., 48 to 54 EFPYs. Therefore, this analysis supplies a basis for BWRVIP-05 to be approved as a technical alternative from the current inservice inspection requirements of ASME Section XI for volumetric examination of the circumferential welds as they may apply in the license renewal period.

In LRA Section 4.2.3, "Reactor Vessel Circumferential Weld Examination Relief," the applicant states that the procedures and training used to limit the frequency of cold overpressure events to the specified number in the current licensed operating period will also be used during the license renewal term. The applicant will apply for an extension of the subject relief for the 60-year extended licensed operating period prior to the end of the initial operating license term for Peach Bottom.

4.2.3.2 Staff Evaluation

Sections 4.2.3 and A.5.1.2 of the LRA discuss inspection of the Peach Bottom RPV circumferential welds. These sections of the LRA indicate that Peach Bottom will use an approved technical alternative in lieu of ultrasonic testing of RPV circumferential shell welds.

The technical alternative is discussed in the staff's final SER of the BWRVIP-05 report, which is enclosed in a July 28, 1998 letter to Carl Terry, BWRVIP Chairman. In this letter, the staff concludes that since the failure frequency for circumferential welds in BWR plants is significantly below the criterion specified in RG 1.154, "Format and Content of Plant-Specific Pressurized Thermal Shock Safety Analysis Reports for Pressurized Water Reactors," and the core damage frequency (CDF) of any BWR plant, since that continued inspection would result in a negligible decrease in an already acceptably low value, elimination of the ISI for RPV circumferential welds is justified. The staff's letter indicated that BWR applicants may request relief from inservice inspection requirements of 10 CFR 50.55a(g) for volumetric examination of circumferential RPV welds by demonstrating that (1) at the expiration of the license, the circumferential welds satisfy the limiting conditional failure probability for circumferential welds in the evaluation, and (2) the applicants have implemented operator training and established procedures that limit the frequency of cold over-pressure events to the frequency specified in the report. The letter indicated that the requirements for inspection of circumferential RPV welds during an additional 20-year license renewal period would be reassessed, on a plant specific basis, as part of any BWR LRA.

Section A.4.5 of report BWRVIP 74 indicates that the staff's SER conservatively evaluated the BWR RPVs to 64 effective full power years (EFPYs), which is 10 EFPYs greater than what is realistically expected for the end of the license renewal period. Since this was a generic analysis, the staff issued RAI 4.2-6 requesting the applicant to submit plant-specific information to demonstrate that the Peach Bottom beltline materials meet the criteria specified in the report. To demonstrate that the vessel has not become embrittled beyond the basis for the technical alternative, the applicant must supply (1) a comparison of the neutron fluence, initial RT_{NDT}, chemistry factor, amounts of copper and nickel, delta RT_{NDT} and mean RT_{NDT} of the limiting circumferential weld at the end of the renewal period to the 64 EFPYs reference case in Appendix E of the staff's SER, and (2) an estimate of conditional failure probability of the RPV at the end of the license renewal term based on the comparison of the mean RT_{NDT} for the limiting circumferential weld and the reference case. Should the applicant request relief from augmented ISI requirements for volumetric examination of circumferential RPV welds during the period of extended operation, the applicant is requested to demonstrate that (1) at the expiration of the license, the circumferential welds satisfy the limiting conditional failure probability for circumferential welds in the evaluation, and (2) the applicant has implemented operator training and established procedures that limit the frequency of cold overpressure events to the frequency specified in the report. In response to the RAI, the applicant compared the limiting circumferential weld properties for Peach Bottom Units 2 and 3 to the information in Table 2.6-4 and Table 2.6-5 of the staff SER on BWRVIP-05 dated July 28, 1998.

The NRC staff used the mean RT_{NDT} value for materials to evaluate failure probability of BWR circumferential welds at 32 and 64 EFPYs in the staff SER dated July 28, 1998. The mean RT_{NDT} value is defined as the sum of the initial (unirradiated) reference temperature (initial RT_{NDT}) and the mean value of the adjustment in reference temperature caused by irradiation (delta RT_{NDT}); it does not include a margin (M). The neutron fluence used in this evaluation was the neutron fluence clad-weld (inner) interface. The mean RT_{NDT} for Peach Bottom Units 2 and 3 is determined to provide a comparison with the values documented in the staff SER. The 54 EFPYs mean RT_{NDT} values thus determined are12 °F and 17 °F for Units 2 and 3, respectively. The staff confirmed these values of mean RT_{NDT} using the data for 54 EFPYs neutron fluence at the clad-weld interface provided by the applicant and the data for Ni and Cu contents in the girth welds from the Peach Bottom Updated Final Safety Analysis Report, Volume 1. For Unit 2, the 54 EFPYs fluence is 1.8E18 n/cm^2, and Cu and Ni contents are 0.056 and 0.96 wt%, respectively. For Unit 3, the 54 EFPYs fluence is 1.4E18 n/cm^2, and Cu and Ni contents are 0.102 and 0.942 wt%. These 54 EFPYs values mean that RT_{NDT} values for Units 2 and 3 are bounded by the 64 EFPYs mean RT_{NDT} value of 70.6 °F used by NRC for determining the conditional failure probability of a circumferential girth weld. The 64 EFPYs mean RT_{NDT} value from the staff SER dated July 28, 1998, is for a Chicago Bridge and Iron (CB&I) weld because CB&I welded the girth welds in the Peach Bottom vessels. Since the Peach Bottom 54 EFPYs value is less than the 64 EFPYs value from the staff SER dated July 28, 1998, the staff concludes that the Peach Bottom RPV conditional failure probability is bounded by the NRC analysis.

The procedures and training used to limit cold overpressure events will be the same those approved by the NRC when Peach Bottom requested to use the BWRVIP-05 technical alternative for the current term (letter from James Hutton of PECO Nuclear to NRC dated February 7, 2000). The staff find the applicant's response to RAI 4.2-6 acceptable because the 54 EFPYs mean RT_{NDT} value for the circumferential weld is bounded by the NRC analysis in the staff SER dated July 28, 1998, and Peach Bottom will be using procedures and training to limit cold overpressure events during the period of extended operation. The UFSAR Supplement needs to include the additional information contained in the applicant's response to RAI 4.2-6 regarding the evaluation of this TLAA. In a letter dated November 26, 2002, responding to this Confirmatory Item, the applicant provided a revision to Section A.5.1.1.3 of the UFSAR Supplement, which describes the analysis of the circumferential welds and adequately addresses this issue.

4.2.3.3 Conclusions

The staff has reviewed the information in LRA Section 4.2.3, "Reactor Vessel Circumferential Weld Examination Relief." On the basis of this review, the staff concludes that the applicant has adequately evaluated the reactor vessel circumferential weld examination relief TLAA, as required by 10 CFR 54.21(c)(1). The staff has also reviewed the UFSAR Supplement and the staff concludes that, the applicant has provided an adequate description of its evaluation of this TLAA for the period of extended operation as required by 10 CFR 54.21(d).

4.2.4 Reactor Vessel Axial Weld Failure Probability

4.2.4.1 Summary of Technical Information in the Application

The staff's SER, enclosed in a letter dated March 7, 2000, to Carl Terry, BWRVIP Chairman, discusses the failure frequency for RPV axial welds and the BWRVIP analysis of the RPV failure frequency for axial welds. The SER indicates that the RPV failure frequency due to failure of the limiting axial welds in the BWR fleet at the end of 40 years of operation is below 5×10^{-6} per reactor year, given the assumptions on flaw density, distribution, and location described in this SER. Since the BWRVIP analysis was generic, the applicant plans to perform plant-specific analyses to confirm that the axial weld failure probability for the Peach Bottom RPVs remains below 5×10^{-6} per reactor year during the period of extended operation, in accordance with 10 CFR Part 54.21(c)(1)(i). The application indicates that the applicant plans to complete these analyses prior to the end of the initial operating license term for Peach Bottom.

4.2.4.2 Staff Evaluation

In its July 28, 1998, letter to Carl Terry, BWRVIP Chairman, the staff identified a concern about the failure frequency of axially oriented welds in BWR RPVs. In response to this concern, the BWRVIP supplied evaluations of axial weld failure frequency in letters dated December 15, 1998, and November 12, 1999. The staff's SER on these analyses is enclosed in a March 7, 2000 letter to Carl Terry. The SER indicates that the RPV failure frequency due to failure of the limiting axial welds in the BWR fleet at the end of 40 years of operation is below 5×10^{-6} per reactor year, given the assumptions on flaw density, distribution, and location described in this SER. Since the results apply only for the initial 40-year license period of BWR plants, applicants for license renewal must submit plant-specific information applicable to 60 years of operation.

The BWRVIP identified the Clinton and Pilgrim reactor vessels as the reactor vessels with the highest mean RT_{NDT} in the BWR fleet. The staff confirmed this conclusion in the SER enclosed in the March 7, 2000, letter by comparing the information in the BWRVIP analysis and the information in the Reactor Vessel Integrity Database (RVID) for all BWR RPV axial welds. The results of the staff calculations are presented in Table 1. The staff calculations used the basic input information for Pilgrim, with three different assumptions for the initial RT_{NDT}. The calculations of the actual Pilgrim condition used the docketed initial RT_{NDT} of -44 °C (-48 °F) and a mean RT_{NDT} of 20 °C (68 °F). A second calculation, listed as "Mod 1" in Table 1, uses an initial RT_{NDT} of -18 °C (0 °F) and a mean RT_{NDT} of 47 °C (116 °F) consistent with the BWRVIP calculations. A third calculation, with an initial RT_{NDT} of -19 °C (-2 °F) and a mean RT_{NDT} of 46 °C (114 °F), was chosen to identify the mean value of RT_{NDT} required to provide a result which closely matches the RPV failure frequency of 5×10^{-6} per reactor-year.

Table 1: Comparison of Results from Staff and BWRVIP

Plant	Initial RT_{NDT} (°F)*	Mean RT_{NDT} (°F)	Vessel Failure Freq.	
			Staff	BWRVIP
Clinton	-30	91	2.73E-6	1.52E-6
Pilgrim	-48	68	2.24E-7	-------
Mod 1 **	0	116	5.51E-6	1.55E-6
Mod 2 ***	-2	114	5.02E-6	-------

* °C = 0.56 x (°F – 32)

** A variant of Pilgrim input data, with initial RT_{NDT} = 0 °F.

*** A variant of Pilgrim input data, with initial RT_{NDT} = -2 °F.

Since the BWRVIP analysis was generic, the staff issued RAI 4.2-7 requesting the applicant to submit plant-specific information to demonstrate that the Peach Bottom beltline materials meet the criteria specified in the report. To demonstrate that the vessel has not become embrittled beyond the basis for the staff and BWRVIP analyses, the applicant was requested to submit (1) a comparison of the neutron fluence, initial RT_{NDT}, chemistry factor, amounts of copper and nickel, delta RT_{NDT}, and mean RT_{NDT} of the limiting axial weld at the end of the renewal period to the reference cases in the BWRVIP and staff analyses; and (2) an estimate of the conditional failure probability of the RPV at the end of the license renewal term based on the comparison of the mean RT_{NDT} for the limiting axial welds and the reference case. If this comparison does not indicate that the RPV failure frequency for axial welds is less than 5 x 10^{-6} per reactor year, the applicant must submit a probabilistic analysis to determine the RPV failure frequency for axial welds.

The applicant presented plant-specific information in response to RAI 4.2-7 to demonstrate that Peach Bottom beltline materials meet the criteria specified in this SER. The SER stated that the axial welds for the Clinton plant are the limiting welds for the BWR fleet, and vessel failure probability calculations determined for Clinton should bound those for the BWR fleet. The NRC used mean RT_{NDT} for the comparison. The mean RT_{NDT} values in the staff's SER were determined using the neutron fluence at the clad/weld (inner) interface, and did not include a margin term. The 54 EFPYs mean RT_{NDT} values for axial welds at clad-weld interface in both Peach Bottom Units 2 and 3 are the same and equal to 11 °F. The staff confirmed this value by using the 54 EFPYs neutron fluence data (2.2E18 n/cm^2) provided by the applicant and the data for Cu and Ni contents (0.182 and 0.181 wt%, respectively) in the axial welds from the Peach Bottom Updated Final Safety Analysis Report, Volume 1; these data are the same for the limiting beltline region axial welds for Units 2 and 3. A comparison of the mean RT_{NDT} value (91 °F) for the Clinton axial weld given in Table 1 with the Peach Bottom value (11 °F) shows that the NRC analysis of Clinton axial welds bounds the Peach Bottom axial welds. Since the Peach Bottom 54 EFPYs value is less than the Clinton value, the staff concludes that Peach Bottom is bounded by the NRC analysis that is enclosed in the March 7, 2000, letter to Carl Terry, and the staff finds the applicant's response acceptable. The UFSAR Supplement needs to include the additional information contained in the applicant's response to RAI 4.2-7 regarding the evaluation of this TLAA. In a letter dated November 26, 2002, responding to this Confirmatory Item, the applicant provided a revision to Section A.5.1.1.4 of the UFSAR Supplement, which describes the analysis of the axial welds and adequately addresses this issue.

4.2.4.3 Conclusions

The staff has reviewed the information in LRA Section 4.2, "Reactor Vessel Neutron Embrittlement." On the basis of this review, the staff concludes that the applicant has adequately evaluated the reactor vessel neutron embrittlement TLAA, as required by 10 CFR 54.21(c)(1). The staff has also reviewed the UFSAR Supplement and the staff concludes that, the applicant has provided an adequate description of its evaluation of this TLAA for the period of extended operation as required by 10 CFR 54.21(d).

4.3 Metal Fatigue

A metal component subjected to cyclic loads may fail at a load magnitude less than its ultimate load capacity as a result of metal fatigue, which initiates and propagates cracks in the material.

The fatigue life of a component is a function of its material, its environment, and the number and magnitude of the applied cyclic loads. Fatigue was a design consideration for piping and components and, consequently, fatigue is part of the current licensing basis (CLB) for Peach Bottom. The applicant identified fatigue analyses as TLAAs for piping and components. The staff reviewed Section 4.3 of the LRA, which discusses fatigue of piping and components, to determine whether the applicant has adequately evaluated the TLAAs as required by 10 CFR 54.21(c).

4.3.1 Summary of Technical Information in the Application

The applicant discussed the fatigue analyses of the Peach Bottom Unit 2 and 3 reactor pressure vessel (RPV) components in Section 4.3.1 of the LRA. The applicant indicated that the analyses have been revised to incorporate changes for power uprate and other operational changes. The applicant's revised analyses indicated that the vessel closure studs may exceed the ASME Code fatigue cumulative usage factor (CUF) limit during the current term of operation and, therefore, included the closure studs in its fatigue management program (FMP). The applicant further indicated that all RPV locations with calculated CUFs that exceed 0.4 are included in the FMP. The FMP monitors plant transients that contribute to the fatigue usage for the following components:

- RPV feedwater nozzles (Loops A and B)
- RPV support skirt
- RPV closure studs
- RPV shroud support
- RPV core spray nozzle safe end
- RPV recirculation inlet nozzle
- RPV recirculation outlet nozzle
- RPV refueling containment skirt
- RPV jet pump shroud support
- residual heat removal (RHR) return line (Loop A)
- RHR supply line (Loops A and B)
- RHR tee (Loops A and B)
- feedwater piping
- main steam piping
- torus penetrations
- torus shell

The applicant discussed the fatigue analyses of the reactor vessel internals (RVI) in Section 4.3.2.1 of the LRA. The applicant indicates that the core shroud, shroud support, and jet pump assembly evaluation were based on a standard plant design and that the core shroud supports were reevaluated to account for the effects of increased recirculation pump starts with the loop outside the thermal limits.

The applicant discussed the RVI embrittlement analysis in Section 4.3.2.2 of the LRA. The applicant's evaluation indicated that the effect of fatigue and embrittlement on end-of-life reflood thermal shock remains valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

The applicant discussed the piping and component fatigue analyses in Section 4.3.3 of the LRA. The applicant designates reactor coolant pressure boundary piping as Group I piping. The applicant indicated that all Group I piping was originally designed to United States of America Standards (USAS) B31.1, 1967. This code did not require an explicit fatigue analysis of piping components. The applicant indicated that the Group I recirculation piping and RHR piping were replaced because of IGSCC concerns and that the replaced piping was analyzed to ASME Section III Class 1 requirements, which include an explicit fatigue analysis. The applicant indicated that a simplified fatigue analysis was developed for the remainder of the Group I piping to estimate CUFs from the operating data. The applicant indicated that fatigue of the Group I piping will be managed by the FMP in accordance with 10 CFR 54.21(c)(1)(iii).

The applicant designates the remainder of the safety-related piping as Group II and III. This piping was designed to the requirements of USAS B31.1. USAS B31.1 requires a reduction in the allowable bending loads if the number of full range thermal bending cycles exceeds 7,000. The applicant's evaluation indicated that the expected number of thermal bending cycles will not exceed the 7,000 limit during the period of extended operation and that the analyses remain valid for the period of extended operation in accordance with 54.21(c)(1)(i).

The applicant discussed the evaluation of the effects of the reactor coolant environment on the fatigue life of components in Section 4.3.4 of the LRA. The applicant relied on industry generic studies to address this issue.

4.3.2 Staff Evaluation

The components of the RCS were designed to codes that contained explicit criteria for fatigue analysis. Consequently, the applicant identified fatigue analyses of these RCS components as TLAAs. The staff reviewed the applicant's evaluation of the identified RCS components for compliance with the provisions of 10 CFR 54.21(c)(1).

The design criterion for ASME Class 1 components involves calculating the CUF. The fatigue damage in the component caused by each thermal or pressure transient depends on the magnitude of the stresses caused by the transient. The CUF sums the fatigue damage resulting from each transient. The design criterion is that the CUF not exceed 1.0. The applicant monitors limiting locations in the RPV, RVI, and RCS piping for fatigue usage through the FMP. The applicant relies on the FMP to monitor the CUF and manage fatigue in accordance with the provisions of 10 CFR 54.21(c)(1)(iii). The staff's evaluation of the FMP is in provided below.

The applicant indicated that all component locations where the 40-year CUFs are expected to exceed 0.4 are included in the FMP. Section 4.3.1 of this SE lists the component locations monitored by the FMP. These locations have been identified in the reactor vessel, vessel internals, reactor coolant system piping, and torus. The applicant indicated that the existing FMP maintains a count of cumulative reactor pressure vessel thermal and pressure cycles to ensure that licensing and design basis assumptions are not exceeded. The applicant also indicated that an improved program is being implemented which will use temperature, pressure, and flow data to calculate and record accumulated usage factors for critical RPV locations and subcomponents. In RAI 4.3-2, the staff requested that the applicant describe how the monitored data will be used to calculate usage factors and to indicate how the fatigue usage will be estimated prior to implementation of the improved program.

The applicant’s May, 1, 2002, response indicated that the FatiguePro monitoring system will be implemented to monitor selected component locations. FatiguePro uses measured temperature, pressure, and flow data to either monitor the number of cycles of design basis transients or to directly compute the stress history to determine the actual fatigue usage for each transient. The applicant indicated that most component locations will be monitored by an automated cycle counting module that will count each licensing basis transient experienced by the plant based on input from monitored plant instruments. The applicant will incorporate the cycle counts obtained since initial plant startup for these component locations. Monitoring of the RPV feedwater nozzles and the RPV support skirt will include a fatigue usage computation based on temperature, pressure, and flow data obtained from monitored plant instruments. The applicant will estimate that the prior fatigue usage for the feedwater nozzles and the RPV support skirt assuming a linear accumulation of fatigue based on the design fatigue values. The applicant indicates that the future monitoring will be used to demonstrate the conservatism of the assumption of a linear accumulation of fatigue based on the design values. The staff considers the applicant’s improved program an acceptable method to monitor fatigue of the critical components.

The applicant indicated that the closure studs are projected to have a CUF > 1.0 during the current period of operation and that the studs are included in the FMP. In RAI 4.3-1, the staff requested the applicant to provide additional discussion regarding the projected CUF for the closure studs.

The applicant’s May 1, 2002, response indicated the fatigue evaluation of the reactor vessel closure studs is based on very conservative analysis techniques. The fatigue usage of the closure studs is being monitored by the FMP. The applicant indicated that corrective action will be initiated prior to reaching a CUF of 1.0 and that corrective actions would include one or more of the following options:

- refinement of the fatigue analysis to lower the CUF to below 1.0
- Repair/replacement of the studs
- manage the effects of fatigue by an inspection program

The applicant committed to provide the NRC with the inspection details of the aging management program for staff review and approval prior to implementation if the last option is selected. An aging management program under this option would be a departure from the design basis CUF evaluation described in the UFSAR Supplement, and therefore, would require a license amendment pursuant to 10 CFR 50.59. In view of the above, the staff finds the applicant’s proposed corrective actions an acceptable approach to manage fatigue of the closure studs. However, in accordance with 10 CFR 54.21(d), this information needs to be added to the UFSAR Supplement, and was the subject of Confirmatory Item 4.3.2-1 discussed below.

The applicant indicated that a fatigue evaluation of the core shroud and jet pump assembly was performed for a plant where the configuration applies to Peach Bottom. The applicant further indicated that the fatigue analyses were reevaluated for the effects of increased pump starts with the loop outside thermal limits. The applicant indicated that fatigue of the critical locations of the jet pump shroud support and RPV shroud support would be managed by the FMP. In RAIs 4.3-3 and 4.3-4, the staff requested that the applicant provide further clarification regarding the revised analysis considering an increase in recirculation pump starts and its impact on the fatigue usage of the core shroud and jet pump assembly.

The applicant’s May 1, 2002, response indicated that although the shroud support is not an ASME component, it was included in the original ASME Code Section III design basis evaluation for the reactor pressure vessel. The applicant further indicated that the core shroud and jet pumps are not ASME components and do not have design basis fatigue evaluations. The applicant indicated the discussion in the LRA regarding the core shroud and jet pump assembly refers to a location on the core shroud support structure where the jet pump adapter is attached.

The applicant’s May 1, 2002, response also described the reevaluation of the core shroud support structure. The Peach Bottom technical specifications require that the temperature difference between an idle recirculation loop and the vessel coolant be 50 °F or less prior to pump restart. Since Peach Bottom experienced recirculation pump starts outside the technical specification limit, a reevaluation was triggered. The applicant accounted for the fatigue associated with these events by using the results from the design basis sudden pump start event. The design basis sudden pump start is a more severe thermal transient than the events that have occurred at Peach Bottom. The calculated fatigue usage from the design basis event is multiplied by the ratio of the temperature difference from the actual pump start to the temperature from the design basis event to obtain the fatigue usage for each pump start event at Peach Bottom. The applicant provided the results from a sample calculation to demonstrate the conservatism of the procedure. On the basis of the results of the applicant’s sample calculation, the staff finds the applicant’s evaluation provides an acceptable method to estimate the fatigue usage resulting from the recirculation pump start events experienced at Peach Bottom.

The applicant's FMP tracks transients and cycles of RCS components that have explicit design basis transient cycles to ensure that these components stay within their design basis. Generic Safety Issue (GSI) 166, "Adequacy of the Fatigue Life of Metal Components," raised concerns regarding the conservatism of the fatigue curves used in the design of these components. Although GSI-166 was resolved for the current 40-year design life of operating plants, the staff initiated GSI-190 to address license renewal. The resolution of GSI-166 for the 40-year design life relied, in part, on conservatism in the existing CLB analyses. This conservatism included the number and magnitude of the cyclic loads postulated in the initial component design. Although GSI-166 was resolved for the current 40-year design life of operating components, the staff identified GSI-190, “Fatigue Evaluation of Metal Components for 60-year Plant Life,” to address license renewal. The NRC closed GSI-190 in December, 1999, concluding:

> The results of the probabilistic analyses, along with the sensitivity studies performed, the iterations with industry (NEI and EPRI), and the different approaches available to the licensees to mange the effects of aging, lead to the conclusion that no generic regulatory action is required, and that GSI-190 is closed. This conclusion is based primarily on the negligible calculated increases in core damage frequency in going from 40 to 60 year lives. However, the calculations supporting resolution of this issue, which included consideration of environmental effects, and the nature of age-related degradation indicate the potential for an increase in the frequency of pipe breaks as plants continue to operate. Thus, the staff concludes that, consistent with existing requirements in

> 10 CFR 54.21, licensees should address the effects of coolant environment on component fatigue life as aging management programs are formulated in support of license renewal.

The applicant indicated that there is sufficient conservatism in the fatigue analyses of components at Peach Bottom to account for the effects of the environment on the design fatigue curves. The applicant relied on the results of generic industry studies to support this argument. The staff has previously commented on these generic industry studies.

By letter dated February 9, 1998, the Electric Power Research Institute (EPRI) submitted two technical reports dealing with the fatigue issue. EPRI topical reports TR-107515, "Evaluation of Thermal Fatigue Effects on Systems Requiring Aging Management Review for License Renewal for the Calvert Cliffs Nuclear Power Plant," and TR-105759, "An Environmental Factor Approach to Account for Reactor Water Effects in Light Water Reactor Pressure Vessel and Piping Evaluations" were part of an industry attempt to resolve GSI-190. As recommended in SECY 95-245, the EPRI analyzed components with high usage factors, using environmental fatigue data. The staff has open technical concerns regarding the EPRI reports. The staff's technical concerns were transmitted to the Nuclear Energy Institute (NEI) by letter dated November 2, 1998, and NEI responded to the staff's concerns in a letter dated April 8, 1999. The staff submitted its assessment of the response in a letter to NEI, dated August 6, 1999. As indicated in the staff's letter, the NEI response did not resolve all of the staff's technical concerns regarding the EPRI reports.

Although the letter dated August 6, 1999, identified the staff's concerns regarding the EPRI procedure and its application to PWRs, the technical concerns regarding the application of the Argonne National Laboratory (ANL) statistical correlations and strain threshold values are also relevant to BWRs. In addition to the concerns referenced above, the staff identified additional concerns regarding the applicability of the EPRI BWR studies in its review of the Hatch LRA. EPRI topical report TR-107943, "Environmental Fatigue Evaluations of Representative BWR Components," addressed a BWR-6 plant, and EPRI topical report TR-110356, "Evaluation of Environmental Thermal Fatigue Effects on Selected Components in a Boiling Water Reactor Plant," used plant transient data from a newer vintage BWR-4 plant. The applicant indicated that these issues were considered in the assessment of metal fatigue at Peach Bottom.

The applicant discussed the impact of the environmental correction factors for carbon and low-alloy steels contained in NUREG/CR-6583, "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels," and the environmental correction factors for austenitic stainless steels contained in NUREG/CR-5704, "Effects of LWR Coolant Environments on Fatigue Design of Austenitic Stainless Steels," on the results of the EPRI studies. The applicant indicated that the impact of the new carbon steel data was not significant. The applicant applied a correction factor of 2.0 to the EPRI generic study results to account for the new stainless steel data.

The applicant indicated that EPRI topical report TR-110356 contained studies that are directly applicable to Peach Bottom because they involved a BWR-4 that is identical to the Peach Bottom design. However, the only components evaluated in TR-110356 are the feedwater nozzle and the control rod drive penetration locations. The staff had previously expressed concerns regarding the applicability of the measured data contained in EPRI topical report TR-110356 to another facility in its review of the Hatch LRA.

The applicant provided the sixty-year CUFs projected for Peach Bottom Units 2 and 3 at the locations evaluated for an older vintage BWR in NUREG/CR-6260, “Application of NUREG/CR-5999, ‘Interim Fatigue Curves to Selected Nuclear Power Plant Components’,” dated March 1995, in Table 4.3.4-3 of the LRA. The applicant indicated that these locations are monitored by the FMP, and that the environmental factors have been adequately accounted for by the conservatism in the design basis transient definitions. The applicant indicated that the vessel support skirt is monitored in lieu of the shell region identified in NUREG/CR-6260 because it is a more limiting fatigue location. The applicant also indicated that, since the location is on the vessel exterior, the environmental fatigue factors do not apply. The staff agrees with the applicant’s statement.

In RAI 4.3-6, the staff requested that the applicant provide an assessment of the six locations identified in NUREG/CR-6260 considering the applicable environmental fatigue correlations provided in NUREG/CR-6583 and NUREG/CR-5704 reports for Peach Bottom Units 2 and 3.

In its May 1, 2002, response, the applicant committed to perform plant-specific calculations for the locations identified in NUREG/CR-6260 for an older vintage BWR plant considering the applicable environmental factors provided in NUREG/CR-6583 and NUREG/CR-5704. The applicant committed to complete these calculations prior to the period of extended operation and take appropriate corrective actions if the resulting CUF values exceed 1.0. The staff finds the applicant’s commitment to complete the plant-specific calculations described above prior to the period of extended operation acceptable. However, in accordance with 10 CFR 54.21(d), this information needs to be added to the UFSAR Supplement.

The applicant indicated that Group II and III piping systems were designed to the requirements of USAS B31.1. The applicant performed an evaluation of the number of cycles expected for the period of extended operation. The applicant’s evaluation indicated that the number of cycles is expected to be substantially less than the 7,000 cycle limit during the period of extended operation. Therefore, the existing analyses remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

The applicant indicated that the NSSS vendor specified a finite number of cycles for each of the elevated-temperature operating modes of the RHR system. The applicant also indicated that it found no description of these design operating cycles in the Peach Bottom licensing basis documents. The applicant indicated that the Group 1 RHR piping inside the drywell was analyzed to the ASME Section III Class 1 requirements. The applicant further indicated that an evaluation of the remaining Group I and Group II piping indicated that the number of thermal cycles would be substantially less the 7,000 cycle limit applicable to piping designed to USAS B31.1. In RAI 4.3-5, the staff requested the applicant to provide further clarification regarding the NSSS vendor specification.

In its May 1, 2002, response, the applicant indicated that the vendor specification contained a description of certain thermal cycles for the original system design. The applicant found no licensing basis requirements (other than design code cycle limits) like those contained in the USAS B31.1 piping design code. The applicant also stated that design to the vendor-specified cycles is not a TLAA, except as it may be included within the design code requirements. The applicant reviewed the design specifications and design codes for components such as pumps and heat exchangers to determine whether they incorporated thermal cycle design considerations. The applicant indicated that no such requirements were identified. As a consequence, the applicant concluded that the only consideration for thermal cyclic loading that needed to be considered was the USAS B31.1 cycle limit. The staff considers the applicant's clarification of this issue satisfactory.

The applicant's UFSAR Supplement for metal fatigue is provided in Section A.4 of the LRA. The applicant describes the FMP in Section A.4.2 and its assessment of metal fatigue for the reactor vessel, reactor vessel internals and piping and components in Section A.5.2. As discussed previously, the applicant indicated that corrective actions to address the fatigue of the reactor vessel closure studs would be initiated prior to the period of extended operation. With the applicant's commitment to include in the UFSAR Supplement a description of the corrective actions to address closure studs as provided above in the response to RAI 4.3-1; and perform plant specific calculations for the locations identified in NUREG/CR-6260 for an older vintage BWR plant considering applicable environmental factors provided in NUREG/CR-6583 and NUREG/CR-5704 as provided above in response to RAI RAI 4.3-6; the staff concludes that the UFSAR Supplement will include an appropriate summary description of the programs and activities to manage aging as required by 10 CFR 54.21(d). This was identified as Confirmatory Item 4.3.2-1 in the draft safety evaluation.

By letter dated November 26, 2202, responding to this Confirmatory Item, the applicant provided a revision to the UFSAR Supplement. The revised UFSAR supplement contains a description of the applicant's proposed corrective actions to address fatigue of the reactor vessel closure studs and the applicant's commitment to evaluate the impact of the reactor water environment on the fatigue life of the components identified in NUREG/CR-6260 for an older vintage BWR. On the basis of the applicant's revised UFSAR supplement, Confirmatory Item 4.3.2-1 is closed.

Fatigue Monitoring Program

Summary of Technical Information in the Application

In Appendix B.4.2 of the LRA, the applicant describes an existing aging management program, the FMP, that is designed to track cyclic and transient occurrences to ensure that reactor coolant pressure boundary components remain within ASME Code Section III fatigue limits. The applicant indicates the FMP will be enhanced to broaden its scope and update its implementation methods. The applicant further indicates that the program will use a computerized data acquisition, recording and tracking system.

Staff Evaluation

The staff's evaluation of the FMP focused on how the program manages fatigue through 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 application indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site controlled corrective actions program pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components subject to aging management review. The staff evaluation of the applicant's corrective actions program is provided separately in Section 3.0.4 of this SER. The corrective actions program satisfies the elements of corrective actions, confirmation process, and administrative controls. The remaining 7 elements are discussed below.

Program Scope: The scope of the program includes the reactor pressure vessel (RPV), reactor vessel internals (RVI), Group I piping reactor coolant pressure boundary and the torus structure. The staff considers the scope of the FMP, which includes components, including components of the reactor coolant pressure boundary, with fatigue analyses, to be acceptable.

Preventive and Mitigative Actions: The applicant referred to the cycle counting procedure as the preventative action for this program. The staff did not identify a need for any additional preventive or mitigative actions.

Parameters Inspected or Monitored: The applicant monitors the transients that contribute to the fatigue usage of the components discussed in Section 4.3 of the SE. The staff finds that monitoring these selected high fatigue usage locations provides an acceptable method to monitor the fatigue usage due to design transients for the RPV, RVI, Group 1 reactor coolant pressure boundary piping, and torus structure.

Detection of Aging Effects: The program continuously monitors operational transients and updates the fatigue analyses of the monitored components . This provides assurance that the fatigue analyses of record remain valid during the period of extended operation. The staff finds this monitoring acceptable.

Monitoring and Trending: As stated previously, the program continuously monitors the operational transients that contribute to the fatigue usage of the monitored components to assure that the fatigue analyses of record remain valid during the period of extended operation. The staff finds that the applicant's continuous monitoring is sufficient to allow for timely corrective actions and is, therefore, acceptable.

Acceptance Criteria: The acceptance criteria consists of maintaining the fatigue usage below the code limit. By meeting these limits, the applicant provides assurance that the monitored components remain within their design limits. Therefore, the staff considers this criteria acceptable.

Operating Experience: The applicant's program was developed in response to concerns that early-life operating cycles at some units caused fatigue usage to accumulate faster than anticipated in the design analysis. The applicant has selected a sample of critical locations to monitor the fatigue usage accumulation. The staff finds that the applicant has adequately considered operating experience in selecting the locations to be monitored.

The staff reviewed Section A.4.2 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 the FMP is equivalent to the information in NUREG-1800. The staff concludes that the UFSAR Supplement provides an adequate summary of program activities as required by 10 CFR 54.21(d).

Conclusions

The applicant references the FMP in its discussion of the fatigue TLAAs as a program to assure that design fatigue limits are not exceeded during the period of extended operation. The staff considers the applicant's program, which monitors the number of plant transients that were assumed in the fatigue design, an acceptable method to manage the fatigue usage of the RCS components within the scope of the program. Therefore, the staff concludes that the FMP will adequately manage thermal fatigue of RCS 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 associated with the FMP for managing the effects of aging as required by 10 CFR 54.21(d).

4.3.3 Conclusions

The staff has reviewed the information in Section 4.3 of the LRA regarding the fatigue analysis of the reactor vessel, reactor vessel internals and piping at Peach Bottom. The applicant's evaluation of Group II and III piping indicates that the analyses will remain valid for the period of extended operation. The applicant monitors the fatigue usage of critical reactor vessel, reactor vessels internals and Group I piping components using its FMP. The staff concludes that the applicant's actions and commitments satisfy the requirements of 10 CFR 54.21(c)(1). The staff has also reviewed the UFSAR Supplement and the staff concludes the applicant has provided an adequate description of its evaluation of this TLAA for the period of extended operation as required by 10 CFR 54.21(d).

4.4 Environmental Qualification

The 10 CFR 50.49 environmental qualification (EQ) program has been identified as a TLAA for the purposes of license renewal. The TLAA of EQ components includes all long-lived passive and active electrical and instrumentation and control (I&C) components and commodities that are located in a harsh environment and are important to safety, including safety-related and Q list equipment, non-safety-related equipment whose failure could prevent satisfactory accomplishment of any safety-related function, and the necessary post-accident monitoring equipment.

The staff has reviewed LRA Section 4.4, "Environmental Qualification of Electrical Equipmne," LRA to determine whether the applicant submitted adequate information to meet the requirements of 10 CFR 54.21(c)(1) for evaluating the EQ TLAA. Paragraph (1) of 10 CFR 54.21(c) requires that a list of EQ TLAA must be provided. The applicant must demonstrate that (i) the analyses remain valid for the period of extended operation, (ii) analyses have been projected to the end of the period of extended operation, or (iii) the effect of aging on the intended functions will be adequately managed for the period of extended operation. The staff also reviewed LRA Section 4.4.2, "GSI-168, 'Environmental Qualification of Low Voltage Instrumentation and Controls (I&C) Cables."

On the basis of this review, the staff requested additional information in a letter to the applicant dated October 26, 2001. The applicant responded to this request for additional information (RAI) in a letter to the staff dated January 2, 2002.

4.4.1 Electrical Equipment Environmental Qualification Analyses

4.4.1.1 Summary of Technical Information in the Application

The Peach Bottom EQ program complies with all applicable regulations and manages equipment thermal, radiation, and cyclic aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. Environmetally qualified equipment must be refurbished, replaced, or have its qualification extended prior to reaching the aging limits established in the aging evaluation. Aging evaluations for environmental qualified equipment that specify a qualified life of at least 40 years are considered TLLAs for license renewal. The following is a list of TLAAs for EQ of electrical equipment.

- GE Co. 4kV pump motors and associated cable
- EGS Grayboot connectors
- Raychem insulated splices for class 1E systems
- Bussman Co. and Gould Shawmut fuses and fuse holders
- EGS quick disconnect connectors
- Limitorque motor-operated valve actuators
- Namco position switches
- ASCO solenoid valves, trip coils, and pressure switches
- UCI splice tape
- Rosemount 1153 Series B transmitters
- GE Co. control station
- Agastat relays
- static O-ring pressure switches
- Cutler Hammer motor control centers
- NDT International accoustical monitors
- Target Rock solenoid valves
- PYCO Resistance Temperature Detectors (RTDs) and thermocouples
- ITT Barton differential pressure switches
- Atkomatic solenoid valves
- Reliance fan motors and SGTS auxiliaries
- Brown Boveri load centers
- Valcor solenoid valves
- GE Co. radiation elements
- Pyle National plug connectors
- General Atomic radiation monitors
- GE electrical penetrations
- Buchanan terminal blocks
- GE terminal blocks
- Marathon terminal blocks
- Weidmueller terminal blocks
- Amp Inc. terminal lugs
- Scotch insulating tape
- GE SIS cable
- Brand Rex cable
- ITT Suprenant 600V control cable
- Okonite 600V power and control cable
- Rockbestos cable

- Foxboro pressure transmitters
- Patel conduit seals
- Jefferson coaxial cable
- Anaconda cable
- HPCI system equipment
- Masoneilan electropneumatic transducer
- Westinghouse Y panels and associated transformers
- Barksdale pressure switches
- H_2 and O_2 analyzer
- Avco pilot solenoid valves
- Rosemout model no. 710-DU trip units
- Westinghouse manual transfer switch

The applicant states that aging effects of the EQ equipment identified in this TLAA will be managed during the extended period of operation by the EQ program activities described in Section B.4.1 of the LRA

4.4.1.2 Staff Evaluation

The staff reviewed Section 4.4.1 of the Peach Bottom LRA to determine whether the applicant submitted adequate information to meet the requirements of 10 CFR 54.21(c)(1). In addition, the staff met with the applicant to obtain clarifications and reviewed the applicant's response to the staff's request for additional information.

TLAA Demonstration for Option 10 CFR 54.21(c)(1)(iii)

For the list of electrical equipment identified in Section 4.4.1 of the LRA, the applicant uses 10 CFR 54.21(c)(1)(iii) in its TLAA evaluation to demonstrate that the aging effects of the EQ equipment identified in this TLAA will be managed during the extended period of operation by the EQ program activities described in Section B.4.1 of the LRA.

The staff reviewed the EQ program to determine whether it will assure that the electrical and I&C components covered under this program will continue to perform their intended function consistent with the current licensing basis for the period of extended operation. The staff's evaluation of the component qualification 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.

Program Scope: The Peach Bottom EQ program includes certain electrical components that are important to safety and could be exposed to harsh environment accident conditions, as defined in 10 CFR 50.49. The staff considers the scope of the program acceptable.

Preventive Actions: 10 CFR 50.49 does not require actions that prevent aging effects. The Peach Bottom EQ program actions that could be viewed as preventive actions include (a) establishing the component service condition tolerance and aging limits (for example, qualified life or condition limit), (b) refurbishment , replacement, or requalification of installed equipment prior to reaching these aging limits, and (c) where applicable, requiring specific installation, inspection, monitoring, or periodic maintenance actions to maintain equipment aging effects within the qualification. The staff considers these are acceptable because 10 CFR 50.49 does not require actions that prevent aging effects.

Parameter Monitored or Inspected: EQ component aging limits are not typically based on condition or performance monitoring. However, per RG 1.89 Rev. 1, such monitoring program are an acceptable basis to modify aging limits. Monitoring or inspection of certain environmental, condition or equipment monitoring may be used to ensure that the equipment is within its qualification or as a means to modify qualification. The staff considers this monitoring appropriate because the program objective is to ensure the qualified life of devices established is not exceeded.

Detection of Aging Effects: 10 CFR 50.49 does not require the detection of aging effects for in-service components. Monitoring of aging effects may be used as a means to modify component aging limits. The staff considers the applicant's program to use monitor of aging effects as a means to modify component aging limits acceptable.

Monitoring and Trending: 10 CFR 50.49 does not require monitoring and trending of component condition or performance parameters of in-service components to manage the effects of aging. EQ program actions that could be viewed as monitoring include monitoring how long qualified component have been installed. Monitoring or inspection of certain environmental, condition or component parameters may be used to ensure that a component is within its qualification or a means to modify the qualification. The staff considers this is acceptable since 10 CFR 50.49 does not require monitoring and trending of component condition or performance parameters of in-service components to manage the effects of aging.

Acceptance Criteria: 10 CFR 50.49 acceptance criteria is that an in-service EQ component is maintained within its qualification including (a) its established aging limits and (b) continued qualification for the projected accident conditions. 10 CFR 50.49 requires refurbishment, replacement, or requalification prior to exceeding the aging limits of each installed device. When monitoring is used to modify a component aging limit, plant-specific acceptance criteria are established based on applicable 10 CFR 50.49(f) qualification methods. The staff considers this is acceptable since it is consistent with 10 CFR 50.49 requirements of refurbishment, replacement, or requalification prior to exceeding the qualified life of each installed device.

Corrective Actions, Confirmation Process, and Administrative Controls: If an EQ component is found to be outside its qualification, corrective actions are implemented in accordance with the PBAPS corrective action process. When unexpected adverse conditions are identified during operational or maintenance activities that effect the environment of a qualified component, the affected EQ component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions. When emerging industry aging issues are identified that affect the qualification of an EQ component, the affected component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions. Confirmatory actions, as needed, are implemented as part of the PBAPS corrective actions. The PBAPS EQ program is subject to administrative controls, which require formal reviews and approvals. The PBAPS EQ program will continue to comply with 10 CFR 50.49 throughout the renewal period including development and maintenance of qualification documentation demonstrating a component will perform required functions during harsh accident conditions. The PBAPS EQ program documents identify the applicable environmental conditions for the component locations. The PBAPS EQ program qualification files are maintained in an auditable form for the duration of the installed life of the component. The PBAPS EQ program documentation is controlled under the quality assurance program. The staff considers this acceptable because corrective actions, confirmation process, and administrative controls are implemented in accordance with the requirement of 10 CFR 50 Appendix B, Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants, that will insure adequacy of corrective actions, confirmation process, and administrative controls.

Operating Experience: The Peach Bottom EQ program includes consideration of operating experience to modify qualification bases and conclusions. Including aging limits. Compliance with 10 CFR 50.49 provides evidence that the component will perform its intended functions during accident conditions after experiencing the detrimental effects of in-service aging. The staff finds that the applicant has adequately addressed operating experience.

The results of the environmental qualification of electrical equipment in Section 4.4. indicate that the aging effects of the EQ of electrical equipment identified in the TLAA will be managed during the extended period of operation under 10 CFR 54.21(c)(1)(iii). However, no information is provided in the submittal on the attribute of a reanalysis of an aging evaluation to extend the qualification life of electrical equipment identified in the TLAA. The important attributes of a reanalysis are the analytical methods, the data collection and reduction methods, the underlying assumptions, the acceptance criteria, and corrective actions. The staff requested the applicant to provide information on the important attributes of reanalysis of an aging evaluation of electrical equipment identified in the TLAA to extend the qualification under 10 CFR 50.49(e).

The applicant responded, in the letter dated January 2, 2002, that the reanalysis of an aging evaluation is normally performed to extend the qualification by reducing excess conservatism incorporated in the prior evaluation. Reanalysis of an aging evaluation to extend the qualification of a component is performed on a routine basis pursuant to 10 CFR 50.49(e) as part of the Peach Bottom EQ program. While a component life limiting condition may be due to thermal, radiation, or cyclical aging, the vast majority of component aging limits are based on thermal conditions. Conservatism may exist in aging evaluation parameters, such as the assumed ambient temperature of the component, an unrealistically low activation energy, or in the application of a component (de-energized versus energized). The reanalysis of an aging evaluation is documented according to Peach Bottom quality assurance program requirements, which requires the verification of assumptions and conclusions. As already noted, important attributes of a reanalysis include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions (if acceptance criteria are not met). These attributes are discussed below.

Analytical Methods

The Peach Bottom EQ program analytical models used in the reanalysis of an aging evaluation are the same as those previously applied during the prior evaluation. The Arrhenius methodology is an acceptable thermal model for performing a thermal aging evaluation. The analytical method used for a radiation aging evaluation is to demonstrate qualification for the total integrated dose (that is, normal radiation dose for the projected installed life plus accident radiation dose). For license renewal, one acceptable method of establishing the 60-year normal radiation dose is to multiply the 40-year normal radiation dose by 1.5 (that is, 60 years/40 years).

The result is added to the accident radiation dose to obtain the total integrated dose for the component. For cyclical aging, a similar approach may be used. Other models may be justified on a case-by-case basis.

Data Collection and Reduction Methods

Reducing excess conservatism in the component service conditions (for example, temperature, radiation, cycles) used in the prior aging evaluation is the chief method used for a reanalysis per the Peach Bottom EQ Program. Temperature data used in an aging evaluation is to be conservative and based on plant design temperatures or on actual plant temperature data. When used, plant temperature data can be obtained in several ways, including monitors used for technical specification compliance, other installed monitors, measurements made by plant operators during rounds, and temperature sensors on large motors (while the motor is not running). A representative number of temperature measurements are conservatively evaluated to establish the temperature used in an aging evaluation. Plant temperature data may be used in an aging evaluation in different ways, such as (a) directly applying the plant temperature data in the evaluation, or (b) using the plant temperature data to demonstrate conservatism when using plant design temperature for an evaluation. Any changes to material activation energy values as part of a reanalysis are to be justified on a plant-specific basis. Similar methods of reducing excess conservatism in the component service conditions used in prior aging evaluations can be used for radiation and cycling aging.

Underlying Assumptions

The Peach Bottom EQ Program EQ component aging evaluations contain sufficient conservatism to account for most environmental changes occurring due to plant modification and events. When unexpected adverse conditions are identified during operational or maintenance activities that affect the normal operating environment of a qualified component, the affected EQ component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions.

Acceptance Criteria and Corrective Actions

Under Peach Bottom EQ Program, the reanalysis of an aging evaluation could extend the qualification of the component. If the qualification can not be extended by reanalysis, the component is be refurbished, replaced, or requalified prior to exceeding the period for which the current qualification remains valid. A reanalysis is to be performed in a timely manner (that is sufficient time is available to refurbish, replace, or requalify the component if the reanalysis is unsuccessful).

The staff finds that the above response acceptable because it now addresses the reanalysis attribute.

4.4.1.3 Conclusions

The staff has reviewed the information in LRA Section 4.4.1 “Electrical Equipment Environmental Qualification Analyse” for the Peach Bottom Units 2 and 3 and concluded that the applicant has submitted adequate information to meet the requirements of 10 CFR 54.21(c)(1) and that the applicant has adequately evaluated the time-limited aging analyses for EQ of electrical equipment consistent with 10 CFR 54.21(c)(1). The staff has also reviewed the UFSAR Supplement and the staff concludes the applicant has provided an adequate description of its evaluation of this TLAA and the associated program for effectivley managing aging for the period of extended operation as required by 10 CFR 54.21(d).

4.4.2 GSI-168, Environmental Qualification of Low Voltage Instrumentation and Control (I&C) Cables

4.4.2.1 Summary of Technical Information in the Application

The applicant states that NRC guidance for addressing GSI-168 “Environmental Qualification of Low Voltage Instrumentation and Control (I&C) Cables,” for license renewal is contained in the June 2, 1998, NRC letter to NEI. In the letter, the NRC states: “With respect to addressing GSI-168 for license renewal, until completion of an ongoing research program and staff evaluations the potential issues associated with GSI-168 and their scope have not been defined to the point that a license renewal applicant can reasonably be expected to address them at this time. Therefore, an acceptable approach described in the Statements of Consideration is to provide a technical rationale demonstrating that the current licensing basis for environmental qualification pursuant to 10 CFR 50.49 will be maintained in the period of extended operation. Although the Statements of Consideration also indicated that an applicant should provide a brief description of one or more reasonable options that would be available to adequately manage the effects of aging, the staff does not expect an applicant to provide the options at this time.”

Environmental qualification evaluations of electrical equipment are identified as time-limited aging analyses for Peach Bottom. The Peach Bottom program (Section B.4.1) evaluates the qualified lifetime of equipment in the EQ program. The existing EQ program requires that equipment qualified for 40 years be reanalyzed prior to entering the period of extended operation. The EQ program requires inclusion of any changes managed by closure of GSI-168. Consistent with the above NRC guidance, no additional information is required to address GSI-168 in a license renewal application at this time.

4.4.2.2 Evaluation

GSI-168, “Environmental Qualification of Low Voltage Instrumentation and Control (I&C) Cables,” was developed to address environmental qualification of electrical equipment. The staff guidance to the industry (letter dated June 2, 1998 from NRC (Grimes) to NEI (Walters) states:

- GSI-168 issues have not been identified to a point that a license renewal applicant can be reasonably expected to address these issues, specifically at this time; and

- An acceptable approach is to provide a technical rationale demonstrating that the CLB for EQ will be maintained in the period of extended operation.

For the purpose of license renewal, as discussed in the statements of consideration (SOC) (60 FR22484, May 8, 1995), there are three options for addressing issues associated with a GSI:

- If the issue is resolved before the renewal application is submitted, the applicant can incorporate the resolution in the LRA.

- An applicant can submit a technical rationale that demonstrate the CLB will be maintained until some later point in the period of extended operation, at which time one or more reasonable options would be available to adequately manage the effects of aging.

- An applicant can develop a plant-specific aging management program that incorporates the resolution of the aging issue.

For addressing issues associated with GSI-168, the applicant continues to manage the effects of aging in accordance with the CLB and considers the evaluation of the EQ TLAA to be technical rationale that demonstrate that the CLB will be maintained during the period of extended operation. The staff finds that the applicant has addressed the issues associated with GSI-168.

4.4.2.3 Conclusions

The staff concludes that the applicant has adequately addressed the issues associated with GSI-168. The applicant will continue to manage the effects of aging in accordance with the CLB and considers the evaluation of the EQ TLAA to be the technical rationale that demonstrates that the CLB will be maintained during the period of extended operation in accordance with 10 CFR 54.21(c)(1). The staff has also reviewed the UFSAR Supplement and the staff concludes the applicant has provided an adequate description of its evaluation of this TLAA for the period of extended operation as required by 10 CFR 54.21(d).

4.5 Reactor Vessel Internals Fatigue and Embrittlement

4.5.1 Summary of Technical Information in the Application

Core Shroud and Top Guide

BWRVIP-26 [Ref.: EPRI topical report TR-107285, "BWR Vessel and Internals Project: BWR Top Guide Inspection and Flaw Evaluation Guidelines," December 1996] lists 5×10^{20} n/cm^2 as the threshold fluence beyond which the components will be significantly affected. The expected 60-year fluence on the shroud, 2.7×10^{20} n/cm^2 x 60/40 = 4.5×10^{20} n/cm^2, is below the 5×10^{20} n/cm^2 damage threshold. License Renewal Appendix C to BWRVIP-26 states that the generic fluence for 60 years on the top guide is 6×10^{20} n/cm^2. The application indicates that although this 60-year fluence will be above the 5×10^{20} n/cm^2 damage threshold, the tensile stresses in this component are very low. At these low stresses fracture is not a concern, and embrittlement is, therefore, not a threat to the intended function. These critical locations in the top guide are exempt from inspection under the approved BWRVIP-26 and no aging management activity is required.

Effect of Fatigue and Embrittlement on End-of-Life Reflood Thermal Shock Analysis

Radiation embrittlement and fatigue usage may affect the ability of certain internals, particularly the core shroud support plate, to withstand an end-of-life reflood thermal shock following a recirculation line break. Thermal shock analyses assume end-of-life fatigue and embrittlement effects and are considered TLAAs.

The applicant evaluated the effects of embrittlement and fatigue on the end-of-life reflood thermal shock analyses. The thermal shock analyses were validated for the 60- year extended operating term. The effects of embrittlement are not significant at higher usage factor locations, and the effects of fatigue are not significant at locations where embrittlement is significant. The net effect in each analyzed location is acceptable. The applicant stated that the thermal shock analyses are, therefore, acceptable for the extended operating period.

4.5.2 Staff Evaluation

Core Shroud and Top Guide

The BWRVIP inspection program for the core shroud and top guide is discussed in topical report EPRI TR-107285, "BWR Vessel and Internals Project, BWR Top Guide Inspection and Flaw Evaluation Guidelines (BWRVIP-26)," December 1996. This report was approved by the staff in a letter from C.I. Grimes (NRC) to C. Terry (BWRVIP) dated December 7, 2000. In its safety evaluation of this report, the staff concluded that due to susceptibility to irradiation-assisted stress corrosion cracking (IASCC), applicants referencing the BWRVIP-26 report for license renewal should identify and evaluate the projected accumulated neutron fluence as a potential TLAA issue.

BWRVIP-26 lists 5×10^{20} n/cm^2 as the threshold fluence beyond which components will be susceptible to IASCC. Since the expected 60-year fluence on the shroud, is below the 5×10^{20} n/cm^2 damage threshold, the core shroud should not be susceptible to IASCC.

The staff in a telephone call on June 17, 2002, with the applicant discussed the impact of neutron radiation on the integrity of top guide components. BWRVIP-26 states that the generic fluence on the top guide for 60 years is 6×10^{20} n/cm^2, which exceeds the 5×10^{20} n/cm^2 damage threshold. The applicant stated that the location on the top guide that will see this high fluence is the grid beam. This is location 1, as identified in BWRVIP-26, Table 3-2, "Matrix of Inspection Options." In its evaluation of the top guide assembly, including the grid beam, General Electric (GE) assumed a lower allowable stress value, acknowledging the high fluence value at this location. The conclusion of this analysis, and the fact that a single failure at this location has no safety consequence, was that no inspection was considered necessary.

The staff is concerned that multiple failures of top guide beams are possible when the threshold fluence for IASCC is exceeded. According to BWRVIP-26, multiple cracks have been observed in top guide beams at Oyster Creek. In addition, baffle-former bolts on PWRs that exceeded the threshold fluence have had multiple failures. In order to exclude the top guide beam from inspection when its fluence exceeds the threshold value, the applicant must demonstrate that failures of multiple beams (all beams that exceed the threshold fluence) will not impact the safe shutdown of the reactor during normal, upset, emergency, and faulted conditions. If this can not be demonstrated, the applicant should propose an aging management program (AMP) for these components which contain the elements in Branch Technical Position RLSB-1 of NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," July 2001. This was Open Item 4.5.2-1.

In Attachment 3 to a letter from M. P. Gallagher to USNRC dated January 14, 2003, the applicant provided a revised Reactor Pressure Vessel and Internals ISI Program (B.2.7) which indicates Peach Bottom will perform augmented inspections for the top guide similar to the inspections of Control Rod Drive Housing (CRDH) guide tubes. The sample size and frequency for CRDH guide tubes is a 10% sample of the total population within 12 years; one half (5%) to be completed within six years. The method of examination is an enhanced visual examination (EVT-1). EVT-1 are utilized to examine for cracks. The program will be implemented prior to the end of the initial operating license term for Peach Bottom. The applicant also stated that it might modify the above agreed-upon inspection program should the BWRVIP-26, "BWR Vessels and Internals Project, BWR Top Guide Inspection and Flaw Evaluation Guidelines (BWRVIP-26)," be revised in the future. This is acceptable to the staff because any modifications to the BWRVIP-26 program through the BWRVIP are reviewed and approved by the staff. Since the aging effect is IASCC, the staff requested the applicant to clarify whether the inspection sample would be in top guide locations that receive the greatest amounts of neutron fluence. In a letter from M. P. Gallagher to USNRC dated January 29, 2003, the applicant concluded that future locations for the top guide inspections will be in the center or close to the center of the core in the high fluence region. The conclusion is based on the applicant's experiences with prior CRDH inspections. Since the applicant has proposed an inspection program which will be able to detect IASCC in locations which receive high neutron fluence, the staff considers the program acceptable; therefore, Open Item 4.5.2-1 is closed.

Effect of Fatigue and Embrittlement on End-of-Life Reflood Thermal Shock Analysis

Radiation embrittlement and fatigue usage may affect the ability of certain reactor vessel internals (RVI), particularly the core shroud support plate, to withstand an end-of-life reflood thermal shock following a recirculation line break. The applicant evaluated the effects of embrittlement and fatigue on the end-of-life reflood thermal shock analysis. The thermal shock analyses were validated for the 60-year extended operating term. The effects of embrittlement are not significant at higher usage factor locations, and the effects of fatigue are not significant at locations where embrittlement is significant. Based on the applicant's evaluation of the impact of fatigue and embrittlement on RVI components, the staff concludes that reflood thermal shock will not significantly affect the capability of RVI components to perform their intended functions during the 60-year extended operating term. The impact of reflood thermal shock on the reactor vessel is discussed in Section 4.2.1 of this SER.

4.5.3 Conclusions

The staff concludes that the reactor vessel internals embrittlement analyses have been evaluated and remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i). Because of the above open item the staff cannot conclude that the UFSAR Supplement provides an adequate description of the evaluation of this TLAA for the period of extended operation as required by 10 CFR 54.21(d). Pending resolution of the open item, the staff will determine if the UFSAR Supplement contains an appropriate summary description.

The effect of fatigue and embrittlement on end-of-life reflood thermal shock analysis have been evaluated and remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i). The staff has also reviewed the UFSAR Supplement and the staff concludes the applicant has provided an adequate description of its evaluation of this TLAA for the period of extended operation as required by 10 CFR 54.21(d).

4.6 Containment Fatigue

The applicant stated that, subsequent to the original design, elements of Peach Bottom containments were reanalyzed for fatigue due to unevaluated pressure and temperature cycles discovered by GE and others, resulting from design basis events, including loss of coolant accidents, safety relief valve discharge, and combinations of loads resulting from these conditions. The re-evaluation consisted of (1) generic analyses applicable to each of several classes of BWR containments and (2) plant-unique analyses (PUA) from the Mark 1 Containment Program. The scope of these analyses included the tori, the drywell-to-torus vents, SRV discharge piping, other torus-attached piping and its penetrations, and the torus vent bellows.

Since there are no hydrodynamic loads acting on the containment, fatigue is not considered in containment design except at penetrations or other stress concentration areas. The drywell shell plate was not evaluated for fatigue in the original design; the PUA also did not reevaluate the drywell, the drywell penetrations, or the process piping penetration bellows which are attached to the piping. No fatigue analyses were identified in the licensing and design basis documents for Peach Bottom for these components. However, the drywell process bellows were originally specified for a finite number of operating cycles, and the design of these bellows is therefore identified as a TLAA.

4.6.1 Fatigue Analysis of Containment Pressure Boundaries: Analysis of Tori, Torus Vents, and Torus Penetrations

4.6.1.1 Summary of Technical Information in the Application

The applicant stated that the tori were originally evaluated for a maximum of 800 SRV events. For the stress cycles associated with SRV and other dynamic events, the PUA calculated maximum design life CUFs in excess of 0.666 for locations on the torus and drywell-to-torus vents. The CUFs for these locations will therefore exceed the ASME Section III Code allowable of 1.0 for the period of extended operation. For most torus, vent, and torus penetration locations the predicted CUF is less than 0.666. However, this CUF value does not provide analytical or event margin. The applicant has therefore chosen a calculated CUF of 0.4 or less as the validation limit for 60 years of operation. Locations whose 40-year CUF exceeds 0.4 will be included in the Fatigue Management Program (FMP), described in Section B.4.2 of the Application.

The FMP counts fatigue stress cycles, tracks fatigue usage factors, and calculates CUFs from modeling equations. For the torus, vent, and torus penetration the CUF model is made up of contributions resulting from normal operation and design basis worst case LOCA cyclic transients. The applicant stated that during normal operation, only SRV load cases contribute to fatigue. As part of the FMP, the fatigue analyses will be revised to show that the SRV contribution will not exceed the Code CUF limit during the period of extended operation. This will be confirmed for the duration of the extended operating period by monitoring fatigue at the high-usage-factor locations in the tori, torus vents and penetrations with the FMP, and tracking the CUFs at these locations using the CUF modeling equations, based on the monitored plant transients. These equations will be updated as necessary, and transient events will be tracked to ensure that the CUF due to normal operating transients will remain less than 1.0. The FMP also permits fatigue reanalysis of the high-usage-factor locations. Conservatism in the original containment PUA may permit the reduction of the total calculated CUFs below the limiting value of 0.4, for which fatigue monitoring would be required. Most locations have been evaluated and remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i). Those that do not remain valid will require management of the aging effects, in accordance with 10 CFR 54.21(c)(1)(iii).

4.6.1.2 Staff Evaluation

The applicant has performed fatigue analyses of the tori, torus vents and torus penetrations that include new Peach Bottom loads. A limit of CUF =0.4 for 40 years as an acceptance criterion was selected to determine if the analyses will remain valid for the period of extended operation. Those locations with CUF<0.4 will remain valid, pursuant to 10 CFR 54.21(c)(1)(i). For those locations that exceed the threshold, the effects of fatigue will be managed during the period of extended operation by the FMP cycle counting and fatigue CUF tracking program, pursuant to 10 CFR 54.21(c)(1)(iii).

4.6.1.3 Conclusions

Pursuant to 10 CFR 54.21(c), the staff finds the proposed acceptance limit CUF of 0.4 acceptable. The staff also finds the use of the FMP, to ensure that fatigue effects will be adequately managed and will be maintained within Code design limits for the period of extended operation, reasonable and acceptable. The applicant has also provided an adequate summary of the information related to the fatigue analysis of the tori, torus vents and penetrations in Section A.5.4.1 of the UFSAR Supplement as required by 10 CFR 54.21(d).

4.6.2 Fatigue Analysis of SRV Discharge Lines and External Torus-Attached Piping

4.6.2.1 Summary of Technical Information in the Application

The SRV discharge lines and external torus-attached piping were analyzed separately from the tori and the torus vents. The analysis included the SRV lines and all piping and branch lines, including small-bore piping attached to the tori, pipe supports, valves, flanges, equipment nozzles and equipment anchors. The applicant stated that the highest fatigue CUF, calculated in the PUA on the basis of 800 SRV actuations was 0.202. The applicant concludes that the fatigue analyses of this piping will remain valid for the period of extended operation.

4.6.2.2 Staff Evaluation

The applicant has described a conservative approach to determining the fatigue evaluation of the SRV discharge lines and external torus-attached piping. The staff finds this approach reasonable and acceptable.

4.6.2.3 Conclusions

Pursuant to 10 CFR 54.21(c)(1)(i), the staff finds that the applicant’s evaluation of the fatigue analyses of the SRV discharge lines and external torus-attached piping demonstrate that these TLAAs will remain valid for the period of extended operation. The applicant has also provided an adequate summary of the information related to the fatigue analysis of the SRV discharge lines and external torus-attached piping in Section A.5.4.2 of the UFSAR Supplement as required by 10 CFR 54.21(d).

4.6.3 Expansion Joints and Bellows Fatigue Analyses: Drywell-to-Torus Vent Bellows

4.6.3.1 Summary of Technical Information in the Application

The applicant has stated that the PUA-calculated fatigue usage factors for the drywell to torus vent bellows are negligible.

4.6.3.2 Staff Evaluation

The staff considers the results of the PUA for these components reasonable and acceptable.

4.6.3.3 Conclusions

Pursuant to 10 CFR 54.21(c)(1)(i), the staff finds that the applicant's evaluation of the fatigue analysis of the drywell-to-torus vent bellows demonstrates that these TLAAs will remain valid for the period of extended operation. The applicant has also provided an adequate summary of the information related to the fatigue analysis of the drywell-to-torus vent bellows in Section A.5.4.3 of the UFSAR Supplement as required by 10 CFR 54.21(d).

4.6.4 Expansion Joint and Bellows Fatigue Analyses: Containment Process Penetration Bellows

Expansion Joint and Bellows Fatigue Analyses: Containment Process Penetration Bellows has been identified as a TLAA for the purposes of license renewal. The staff reviewed LRA Section 4.6.4 to determine whether the applicant submitted adequate information to meet the requirements of 10 CFR 54.21(c).

4.6.4.1 Summary of Technical Information in the Application

The applicant stated that at Peach Bottom, the only containment process piping expansion joints and bellows subjected to significant thermal expansion and contraction cycling are those between the drywell shell penetrations and process piping. The design of containment boundary components for a stated number of cycles over the design life constitutes a TLAA, in accordance with 10 CFR 54.3. Some process expansion joints have been replaced with components designed to later code and specification requirements. These bellows were designed to the requirements of ASME Code Section III and specified a minimum of 200 "startup-and-shutdown" cycles and a minimum of 1,500 "normal operating" cycles. Both the original and replaced components were designed for a number of equivalent full-temperature thermal cycles in excess of their specifications. The bellows were initially designed and supplied for operation in excess of 10,000 operating and thermal cycles. The replacement bellows were designed for operation in excess of 50,000 cycles. The PUA did not include any reanalysis of the expansion joints.

4.6.4.2 Staff Evaluation

Based on the applicant's description, the design cycles of the original and replacement bellows exceed the requirements of the original specifications and the estimate of the thermal cycles that might be expected to occur during the period of extended operation. The fatigue analyses of the penetrations therefore demonstrate ample margin for continuing operation during the period of extended operation.

4.6.4.3 Conclusions

Pursuant to 10 CFR 54.21(c)(1)(i), the staff finds that the applicant's evaluation of the fatigue analysis of the expansion joint and bellows demonstrates that these TLAAs will remain valid for the period of extended operation. The applicant has also provided an adequate summary of the information related to the fatigue analysis of the containment process penetration bellows in Section A.5.4.4 of the UFSAR Supplement as required by 10 CFR 54.21(d).

4.7 Other Plant-Specific TLAAs

4.7.1 Reactor Vessel Main Steam Nozzle Cladding Removal Corrosion Allowance

4.7.1.1 Summary of Technical Information in the Application

The original reactor vessel corrosion allowances were conservative values intended to encompass 40 years of operation without reliance on a particular corrosion rate. However, a subsequent calculation to justify removal of the main steam nozzle cladding used a time-dependent corrosion rate for 40 years and is therefore a TLAA.

The applicant evaluated corrosion data for unclad portions of the vessel interior were evaluated and predicted a loss of about 0.030 inches in 60 years. The main steam nozzle clad removal calculation was validated to confirm that the 1/16 inch (.065 inch) corrosion allowance is conservative for 60 years of operation.

4.7.1.2 Staff Evaluation

In response to RAI 4.7-1, the applicant identified the basis for the corrosion rate and the sources for the data. Based on the average of the available data, corrosion rates were determined for high- and low-temperature operating conditions. Assuming 54 years at high temperature and 6 years at low temperature (90% availability for 60 years of operation), and doubling the average corrosion rate, the amount of corrosion for 60 years of operation was estimated to be 0.030 inch. The analysis is acceptable to the staff because the analysis used the average of all available data and conservatively doubled the average corrosion rate to estimate the amount of corrosion for 60 years of operation. Based on the applicant's conservative analysis of the predicted loss of material resulting from corrosion during 60 years of operation, the staff concludes that the corrosion allowance identified when the clad was removed from the main steam nozzles is valid for 60 years of operation.

4.7.1.3 Conclusions

The reactor vessel main steam nozzle clad removal corrosion allowances have been evaluated and remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i). The applicant has also provided an adequate summary of the information related to the above analysis in Section A.5.5.1 of the UFSAR Supplement as required by 10 CFR 54.21(d).

4.7.2 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"

4.7.2.1 Summary of Technical Information in the Application

The applicant describes its evaluation of the feedwater nozzle and control rod drive return line nozzle cracking TLAA in LRA Section 4.7.2, "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*," and in Section A.5.6, "Inservice Flaw Growth Analyses that Demonstrate Structural Integrity for 40 Years," of Appendix A, "Updated Final Safety Analysis Report (UFSAR) Supplement," of the LRA. The applicant proposes to manage crack growth associated with the TLAA by an NRC-approved BWR Owners Group (BWROG) inspection program.

By late 1970s, inservice inspections (ISIs) discovered cracking on the inside surface of feedwater and control rod drive return line (CRDRL) nozzles at several BWR plants in the United States. The cracking was attributed to thermal cycling due to turbulent mixing of relatively cooler CRDRL water and leaking feedwater with hot downcomer flow. The CRDRL nozzles have been capped at Peach Bottom Units 2 and 3 to eliminate cracking due to thermal cycling.

The applicant has taken the following three actions as recommended by NUREG-0619 and Generic Letter 81-11 to reduce or eliminate the causes of cracking of feedwater nozzles: (a) installation of improved triple thermal sleeves with dual piston ring seals, (b) removal of cladding from the nozzle bore and blend radii, and (c) improvement of the low-flow controller. The applicant now uses the NRC-approved improved BWROG inspection and management methods in lieu of NUREG-0619 methods. The BWROG methods depend on a fracture mechanics analysis and ultrasonic inspection from the vessel and nozzle exterior. The fracture mechanics analysis is used to determine the inspection interval. This analysis is not a TLAA because it does not involve time-limited assumptions defined by the current operating term.

The nozzle crack growth, however, must be acceptable for the period of extended operation to ensure the continued validity of the assumptions of fatigue analyses for the reactor pressure vessel, which are TLAAs.

The feedwater nozzle is subject to the combined effect of long-term, low-cycle thermal fatigue due to heatup, cooldown, and other operational transients (which affects the entire vessel, including the nozzle wall) and high-cycle thermal fatigue due to leaking feedwater (which only affects inner surface of the feedwater nozzle). The UFSAR description of this issue includes an evaluation of this combined effect, which is a TLAA. However, these two fatigue effects are separable. Table 3.1-1 of the LRA includes both cumulative fatigue damage and cracking as aging effects due to fatigue for BWR feedwater nozzle. The applicant proposes the use of NRC-approved BWROG inspection methods, which no longer depend on this combined fatigue evaluation, to manage cracking due to rapid thermal cycling, in accordance with the requirements of 10 CFR 54.21(c)(1)(iii).

4.7.2.2 Staff Evaluation

The relatively cooler water leaking past the loosely fitted thermal sleeves installed inside the feedwater nozzles has caused cracking of these nozzles in a large number of BWR plants in the United States during 1970s. The cracks were discovered on the inside surface of the nozzles at the blend radius and bore. The leaking water (also called bypass leakage) turbulently mixed with hot downcomer flow in the annulus between the nozzle and thermal sleeve and put high-cycle fatigue loads on the nozzle inside wall. The cracks initiated by the high-cycle fatigue are arrested at a shallow depth (~6 mm) because the thermal stresses induced by the high-cycle fatigue have steep gradients and shallow depth. These cracks are further propagated by low-cycle fatigue due to plant heatup, cooldown, and feedwater on-off transients. These transients produce large, throughwall, stress cycles on the nozzle wall and in time could drive the cracks to significant depth. Such cracking has been discovered in the feedwater nozzles at Peach Bottom Units 2 and 3.

Similarly, the relatively cooler water passing through the CRDRL nozzle turbulently mixes with hot downcomer flow and causes cracking on the inside surface of the nozzle and also on the wall of the reactor pressure vessel beneath the nozzle. Such cracking has been discovered at the CRDRL nozzles at Peach Bottom Units 2 and 3. The applicant reports that these nozzles were capped after the cracks were repaired and are no longer susceptible to damage due to rapid thermal cycles. Therefore, the staff concludes that cracking of the CRDRL nozzles no longer requires aging management for license renewal at Peach Bottom Units 2 and 3.

NUREG-0619 recommended that the licensees take the following six actions to reduce the potential for initiation and growth of cracks in the inner nozzle areas: (1) remove the cladding from the inner radii; (2) replace loose-fitting or interference-fitting sparger thermal sleeves; (3) evaluate the acceptability of the flow controller; (4) modify operating procedures to reduce thermal fluctuations; (5) reroute reactor water cleanup system (RWCU) discharge to both feedwater loops; and (6) conform to the inspection interval specified in Table 2 of NUREG-0619. In 1981, the NRC staff issued Generic Letter 81-11 to amend the recommendations in NUREG-0619, thereby allowing plant-specific fracture mechanics analysis in lieu of hardware modifications.

The first three of the NUREG-0619 recommendations have been implemented at Peach Bottom Units 2 and 3: cladding has been removed from the nozzle bores and blend radii, improved triple thermal sleeves with dual piston ring seals have been installed, and the low-flow controllers have been improved. The implementation of these recommendations has been effective in preventing cracking of the feedwater nozzle. An industry report, GE-NE-523-A71-0594-A, Revision 1, “Alternate BWR Feedwater Nozzle Inspection Requirements,” May 2000, states that no new cracking has been identified in the BWR feedwater nozzles since 1984.

The feedwater nozzle is susceptible to the combined effect of low-cycle thermal and mechanical fatigue due to heatup, cooldown, and feedwater on-off transients and high-cycle thermal fatigue due to bypass leakage. The evaluation of this combined effect is a TLAA. The applicant, however, states that these two fatigue effects are separable and proposes two different aging management programs to manage them. The aging effect of low-cycle fatigue is cumulative fatigue damage, whereas the aging effects of high-cycle thermal fatigue is cracking. Several of the NUREG-0619 recommendations implemented at Peach Bottom Units 2 and 3 have reduced the potential for racks due to rapid thermal cycling damage. Consequently, the susceptibility to crack initiation at the feedwater nozzle blend radius and bore has also been reduced. This reduced susceptibility to cracking is supported by the significant field experience with the successful prevention of cracks in feedwater nozzles since implementation of the NUREG-0619 recommendations, as mentioned earlier. So the remaining aging effect of high-cycle fatigue is the growth of an existing crack that was initiated earlier by rapid thermal cycling caused by bypass leakage. Therefore, the staff conclude that the separation of two fatigue effects, cumulative fatigue damage and crack growth, is justified.

NUREG-0619 identified the inservice inspection requirements based on the state-of-the-art in the late 1970s. The required inservice inspection included both ultrasonic testing (UT) of the entire nozzle and dye-penetrant testing (PT) of various portions of blend radius and bore. Since the issuance of NUREG-0619, significant advances have been made in UT inspection technology, and significant field experience has been gained on the successful prevention of cracks in feedwater nozzles. As a result of these improvements, BWROG proposed that UT inspections replace the PT inspections specified in NUREG-0619, and that UT inspection intervals be based on sparger-sleeve configurations and specific UT inspection methods as described in the report GE-NE-523-A71-0594-A, Revision 1. This report specifies UT of specific regions of the nozzle inner blend radius and bore. The nozzle inner blend radius region is more limiting from a fracture mechanics point of view than the bore region. The UT examination techniques and personnel qualifications are in accordance with the guidelines of GE-NE-523-A71-0594-A, Revision 1. The examination techniques include manual, automatic and phased-array UT methodologies. In a letter from SA. Richards to W. Glenn Warren, dated March 10, 2000, “Final Safety Evaluation of BWR Owners Group Alternative BWR Feedwater Nozzle Inspections,” the NRC staff accepted the proposed BWROG inspection methods and fracture mechanics analysis. These NRC-approved BWROG inspection methods and inspection intervals are currently being used at Peach Bottom. The applicant proposes to continue the use of these inspection methods during the extended period of operation.

The BWROG inspection methods require fracture mechanics analysis to estimate the time required for an assumed crack (an initial crack depth of ~6 mm [0.5 inch]) to reach the generic allowable value (1 inch) or to reach an allowable value based on plant-specific analysis. Plant-specific analysis must follow the recommendations of Section 5.6 of the report GE-NE-523-A71-0594-A, Revision 1. The BWROG method determines the inspection interval as a fraction of the time taken for this crack growth. The magnitude of the fraction and therefore the size of the inspection interval depend on the thermal sleeve-sparger design configuration, the UT inspection technique employed, and the specific region of the nozzle inspected. The maximum allowable inspection interval for the nozzle inner blend radius is 10 years. This fracture mechanics analysis is not a TLAA because it is used to determine the inspection interval and not to determine whether the crack growth at the end of the current 40-year licensed operating period is acceptable, and so does not involve time-limited assumptions for the current operating term. The GE generic fracture mechanics evaluation show that there is significant margin available to the allowable depth of 1 inch. The report recommends that the fatigue crack growth curves from Section XI of the ASME Code be utilized in the fracture mechanics analysis. To predict crack growth, Peach Bottom performed the fracture mechanics analysis of feedwater nozzle subjected to thermal cycles expected during the extended period of operation. Analysis at Peach Bottom predicts that growth from the assumed initial flaw size to the allowable value will take about 60 years.

The NRC-approved BWROG inspection methods, along with acceptance criteria and corrective actions are included in the aging management program presented in LRA Section B.2.7, “RPV and Internals ISI Program.” The evaluation of this program is presented in Section 3.0.3.9 of this

SER. In addition to these inspections, the applicant proposes to do a periodic review of the fracture mechanics analysis, in conjunction with the fatigue management program presented in Section B.4.2 of the LRA, to ensure that the fracture mechanics evaluation remains bounding and applicable for its intended purpose. The staff finds the applicant's commitments acceptable.

4.7.2.3 Conclusions

The staff has reviewed the information presented in LRA Section 4.7.2, "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*." On the basis of this review, the staff concludes that the applicant has adequately evaluated this TLAA, as required by 10 CFR 54.21(c)(1).   Specifically, the staff concludes that the RPV and Internals ISI program will ensure that any cracking in the feedwater nozzle will be adequately detected and managed, within the limits of the supporting fracture mechanics analyses, for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(iii). The applicant has also provided an adequate summary of the information related to the above analysis in Section A.5.6.1 of the UFSAR Supplement as required by 10 CFR 54.21(d).

4.7.3 Fracture Mechanics of ISI-Reportable Indications for Group 1 Piping: As-forged Laminar Tear in a Unit 3 Main Steam Elbow Near Weld 1-B-3BC-LDO Discovered During Preservice UT

4.7.3.1 Summary of Technical Information in the Application

The applicant reported that a preservice UT volumetric examination discovered an imbedded as-forged laminar tear in the Unit 3 main steam elbow material. The UT indication did not extend to the weld.

To determine the effect of the flaw on the life of the steam line, the applicant performed an ASME Section III Class 1 fatigue analysis of the main steam elbow with the flaw, considering 40 years of operation. The analysis determined that the primary, secondary, and primary plus secondary stresses are within the Code allowable limits, and calculated a 40-year cumulative usage factor (CUF) of 0.012. The applicant stated that if the laminar tear extended to the weld joint, the CUF would rise to 0.036, and would not exceed to 0.054 for the period of extended operation. These values are below the Code design limit of 1.0.

4.7.3.2 Staff Evaluation

Ordinarily, fatigue analyses of steam lines in accordance with ASME Section III Class 1 are not required, since these are not Class 1 components. However, for the elbow with flaws, the applicant chose to perform an ASME Section III Class 1 fatigue analysis and demonstrate that the calculated CUF is below the Code design limit of 1.0 for 40-year operation and also for the period of extended operation. A CUF of 1.0 is considered the approximate threshold at which a fatigue crack may initiate and propagate. The staff's interpretation is that the applicant's intent was to consider the discovered flaw as a local discontinuity in the elbow geometry. The effect of the flaw is accounted for by the introduction of a fatigue strength reduction factor, or an equivalently stress concentration factor, as specified in the ASME Section III Subsection NB design rules. By reporting that the CUF is considerably below the design limit of 1.0, the staff concludes that the applicant has provided reasonable assurance that the flaw will not propagate during operation during the 40-year life of the plant and the period of extended operation.

4.7.3.3 Conclusions

Pursuant to 10 CFR 54.21(c)(1)(i), the staff finds that the applicant's evaluation of the effect of a laminar tear discovered during a preservice ultrasonic examination on the structural integrity of the steam line elbow by an ASME Section III Class 1 fatigue analyses is acceptable, and that the applicant has demonstrated that this TLAA will remain valid for the period of extended operation. The applicant has also provided an adequate summary of the information related to the fatigue evaluation of a laminar tear discovered during a preservice inspection in a steam line elbow in Section A.5.6.2 of the UFSAR Supplement as required by 10 CFR 54.21(d).

5 REVIEW BY THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

On September 13, 2002, the staff issued its safety evaluation report (SER) with open and confirmatory items related to the license renewal of Peach Bottom Atomic power station, Units 2 and 3. On October 30, 2002, the Advisory Committee on Reactor Safeguards (ACRS) conducted a review of the 10 CFR Part 54 portion of the Peach Bottom license renewal application and the SER with open items. The staff finalized and issued its SER related to the license renewal of the Peach Bottom Atomic Power Station, Units 2 and 3, on February 5, 2003.

During its 500th meeting on March 6, 2003, the ACRS full committee completed its review of the Peach Bottom license renewal application and the NRC staff's SER. The ACRS documented its findings in a letter to the Commission dated March 14, 2003. A copy of the ACRS full committee report is attached.

6 CONCLUSIONS

The staff reviewed the Peach Bottom Atomic Power Station, Units 2 and 3, license renewal application in accordance with Commission regulations and the NRC "Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants," dated July 2001. The Commission's regulatory standards for issuance of a renewed license are in 10 CFR 54.29.

In a safety evaluation report (SER) issued on September 13, 2002, the staff identified a number of open and confirmatory items. All of those items have been resolved, as discussed in this SER. On the basis of its evaluation of the application, as discussed above, the staff concludes that: (1) actions have been identified and have been or will be taken with respect to managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require an aging management review under 10 CFR 54.21(a)(1), and (2) actions have been identified and have been or will be taken with respect to time-limited aging analyses that have been identified to require review under 10 CFR 54.21(c). Accordingly, the staff finds that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the current licensing basis for the Peach Bottom Atomic Power Station, Units 2 and 3. The staff notes that the requirements of subpart A of 10 CFR Part 51 are documented in the final plant-specific supplement to the Generic Environmental Impact Statement issued on January 22, 2003.

APPENDIX A
CHRONOLOGY

This appendix contains a chronological listing of routine licensing correspondence between the U.S. Nuclear Regulatory Commission (NRC) staff and Exelon Generation Company, LLC (Exelon), regarding the NRC staff's review of the Peach Bottom Atomic Power Station (PBAPS), Unit 2 and 3, license renewal application (LRA) (Docket Nos. 50-277 and 50-278).

July 2, 2001	In a letter signed by J. Benjamin, Exelon submitted its application to renew the operating licenses of Peach Bottom Atomic Power Station, Units 2 and 3. In its submittal, Exelon provided the original of the application, 17 paper copies and 30 copies of the application on CD-ROM.
July 2, 2001	In a letter signed by J. Benjamin, Exelon submitted four sets of boundary drawings to the NRC.
July 18, 2001	In a letter signed by D. Matthews, NRC informed Exelon that the NRC had received its application to renew the operating licenses of Peach Bottom Atomic Power Station, Units 2 and 3, on July 2, 2001, and that Mr. Raj Anand was appointed as the project manager for the Peach Bottom LRA.
July 25, 2001	NRC published a *Federal Register* notice (FRN) of the receipt of the Peach Bottom Atomic license renewal application.
August 27, 2001	In a letter signed by R. Anand, NRC issued a summary of the public meeting held on August 14, 2001. In this meeting, Exelon made a presentation to the NRC staff and members of the public regarding information contained in the Peach Bottom LRA.
August 31, 2001	NRC published an "acceptance for docketing and opportunity for hearing" *Federal Register* notice (FRN) regarding the Peach Bottom LRA.
September 5, 2001	In a letter signed by D. Matthews, NRC informed Exelon that the NRC staff determined that the contained information in the Peach Bottom LRA submitted on July 2, 2001, was acceptable for docketing and sufficient for the staff to begin its review.
October 26, 2001	In a letter signed by R. Anand, NRC issued the summary of a public meeting between the staff and Exelon representatives. The meeting was held on September 24 and 25, 2001, to discuss the scoping and screening methodology and electrical sections of the PBAPS LRA.
October 30, 2001	In a letter to Exelon signed by R. Anand, the NRC staff requested additional information regarding the scoping and screening methodology discussed in Section 2.1 of the Peach Bottom LRA.

November 5, 2001	In a letter to Exelon signed by R. Anand, the NRC staff issued a summary of the public meeting held on October 22, 2001. In this meeting Exelon provided clarifications of the scoping and screening process discussed in the Peach Bottom LRA.
November 16, 2001	In a letter to Exelon signed by R. Anand, the NRC staff provided the schedule for the review of the Peach Bottom Atomic Power Station, Unit 2 and 3, LRA.
November 16, 2001	In a letter signed by M.P. Gallagher, Exelon submitted its response to the NRC staff's request for additional information (RAI) dated October 30, 2001, regarding Section 2.1-1 of the Peach Bottom LRA.
December 14, 2001	In a letter signed by R. Anand to Exelon, the NRC staff provided the findings of its audit of the scoping and screening methodology use in the Peach Bottom LRA.
January 23, 2002	In a letter to Exelon signed by R. Anand, the NRC staff requested additional information regarding the scoping and screening methodology discussed in Section 2.1.2 of the Peach Bottom LRA.
January 23, 2002	In a letter to Exelon signed by R. Anand, the NRC staff requested additional information regarding the aging management of electrical and instrument and control discussed in Section 3.6 of the Peach Bottom LRA.
January 23, 2002	In a letter signed by R. Anand, NRC issued a summary of a teleconference between the staff and Exelon representatives. This teleconference was held on December 26, 2001, to clarify information provided by Exelon in Section 3.2 of the Peach Bottom LRA.
January 28, 2002	In a letter signed by R. Anand, NRC issued a summary of a teleconference between the staff and Exelon representatives. This teleconference was held on January 16, 2002, to clarify information provided by Exelon in Section 3.5 of the Peach Bottom LRA.
January 30, 2002	In a letter signed by R. Anand, NRC issued a summary of a teleconference between the staff and Exelon representatives. This teleconference was held on January 3, 2002, to clarify information provided by Exelon in Section 4.3 of the Peach Bottom LRA.
February 6, 2002	In a letter signed by R. Anand, NRC issued a summary of a teleconference between the staff and Exelon representatives. This teleconference was held on February 4, 2002 to clarify information provided by Exelon in Section 2.3 of the Peach Bottom LRA.
February 6, 2002	In a letter to Exelon signed by R. Anand, the NRC staff requested additional information regarding the aging management of the reactor

	coolant system, the engineered safety feature systems, the auxiliary systems, and the steam and power conversion systems as discussed in Sections 3.1, 3.2, 3.3, and 3.4 of the Peach Bottom LRA.
February 7, 2002	In a letter to Exelon signed by R. Anand, the NRC staff requested additional information regarding time-limited aging analyses, identification of TLAAs, reactor vessel embrittlement, metal fatigue, and reactor vessel main steam nozzle cladding removal corrosion allowance as discussed in Sections 4.0, 4.1, 4.2, 4.3, and 4.7.1 of the Peach Bottom LRA.
February 28, 2002	In a letter signed by M.P. Gallagher, Exelon submitted its response to the NRC staff's RAI dated January 23, 2002, regarding Section 2.1.2 of the Peach Bottom LRA.
March 1, 2002	In a letter to Exelon signed by R. Anand, the NRC staff requested additional information regarding the aging management of containment, structure, and component supports as discussed in Section 3.5 of the Peach Bottom LRA.
March 1, 2002	In a letter to Exelon signed by R. Anand, the NRC staff requested additional information regarding the scoping and screening results for reactor coolant system, engineered safety features systems, and auxiliary systems as discussed in Sections 2.3.1, 2.3.2, and 2.3.3 of the Peach Bottom LRA.
March 6, 2002	In a letter to Exelon signed by R. Anand, the NRC staff requested additional information regarding the aging management activities as discussed in Appendix B of the Peach Bottom LRA.
March 12, 2002	In a letter to Exelon signed by R. Anand, the NRC staff requested additional information regarding the aging management activities as discussed in Appendix B of the Peach Bottom LRA.
March 12, 2002	In a letter to Exelon signed by R. Anand, the NRC staff requested additional information regarding the plant-level scoping, and screening results for mechanical, structures, component supports, and electrical and instrumentation and controls as discussed in the Sections 2.2, 2.3, 2.4, and 2.5 of the Peach Bottom LRA.
March 12, 2002	In a letter to Exelon signed by R. Anand, NRC issued a summary of a teleconference between the staff and Exelon representatives. This teleconference was held on January 22, 2002, to clarify information provided by Exelon in Sections 3.3 and 3.4 of the Peach Bottom LRA.
March 13, 2002	In a letter to Exelon signed by R. Anand, NRC issued a summary of a teleconference between the staff and Exelon representatives. This teleconference was held on January 22, 2002, to clarify information provided by Exelon in Sections 3.1and 4.1 of the Peach Bottom LRA.

April 5, 2002	In a letter to Exelon signed by R. Anand, NRC issued a summary of a teleconference between the staff and Exelon representatives. This teleconference was held on February 20, 2002, to clarify information provided by Exelon in Section 2.0 of the Peach Bottom LRA.
April 29, 2002	In a letter signed by M.P. Gallagher, Exelon submitted its response to the NRC staff's RAIs dated January 23, 2002, regarding Section 3.6 of the Peach Bottom LRA.
April 29, 2002	In a letter signed by M.P. Gallagher, Exelon submitted its response to the NRC staff's RAIs dated March 12, 2002, regarding the Appendix B aging management activities discussed in the Peach Bottom LRA.
May 01, 2002	In a letter signed by M.P. Gallagher, Exelon submitted its response to the NRC staff's RAIs dated February 7, 2002, regarding Section 4.0 of the Peach Bottom LRA.
May 06, 2002	In a letter signed by M.P. Gallagher, Exelon submitted its response to the NRC staff's RAIs dated March 1, 2002, regarding Section 2.3 of the Peach Bottom LRA.
May 06, 2002	In a letter signed by M.P. Gallagher, Exelon submitted its response to the NRC staff's RAIs dated February 6, 2002, regarding Sections 3.1, 3.2, 3.3, and 3.4 of the Peach Bottom LRA.
May 14, 2002	In a letter signed by M.P. Gallagher, Exelon submitted its response to the NRC staff's RAIs dated March 6, 2002, regarding Appendix B aging management activities discussed in the Peach Bottom LRA.
May 21, 2002	In a letter signed by M.P. Gallagher, Exelon submitted its response to the NRC staff's RAIs dated March 1, 2002, regarding Section 3.5 of the Peach Bottom LRA.
May 21, 2002	In a letter signed by M. Gallagher, Exelon submitted its response to the NRC staff's RAIs dated January 23, February 6, 2002, regarding RAI 2.1.2-3, 2.1.2-4, and 3.3-1.
May 22, 2002	In a letter signed by M.P. Gallagher, Exelon submitted its response to the NRC staff's RAIs dated March 12, 2002, regarding Section 2.0 of the Peach Bottom LRA.
May 31, 2002	In a NRC Region I letter to Exelon, signed by W. Lanning, the staff submitted Inspection Report 50-277/02-09, 50-278/02-09 concerning the scoping and screening of systems, structures, and components discussed in the Peach Bottom LRA.

June 10, 2002	In a letter signed by M.P. Gallagher, Exelon submitted its response to the NRC staff's RAIs dated March 12, 2002, regarding Section 4.2-7 of the Peach Bottom LRA.
July 18, 2002	In a letter to Exelon signed by R. Anand, NRC issued a summary of a teleconference between the staff and Exelon representatives. This teleconference was held on June 17, 2002 to clarify information provided by Exelon concerning reactor vessel internals fatigue and embrittlement in Section 4.3.2 of the Peach Bottom LRA.
July 18, 2002	In a letter to Exelon signed by R. Anand, NRC issued a summary of a teleconference between the staff and Exelon representatives. This teleconference was held on January 23 and March 12, 2002, to clarify information provided by Exelon concerning scoping and aging management of electrical and instrumentation and controls in Sections 2.5 and 3.6 of the Peach Bottom LRA.
July 30, 2002	In a letter signed by M.P. Gallagher, Exelon submitted its response to the NRC staff's RAI concerning fire protection activities, aging effects for carbon steel piping in an outdoor environment, and recovery path during station blackout system (SBO).
August 6, 2002	In a letter signed by P. Kuo, NRC informed Exelon that David L. Solorio was appointed Project Manager for the Peach Bottom LRA.
September 20, 2002	In a letter to Exelon signed by W. Dam, NRC issued a summary of a teleconference between the staff and Exelon representatives. This teleconference was held on August 6 & 8, 2002, to clarify information provided by Exelon of the Peach Bottom LRA.
September 24, 2002	In a letter to Exelon signed by D. Solorio, NRC issued a summary of a teleconference between the staff and Exelon representatives. This teleconference was held on July 23, August 19, and September 5 & 6, 2002, to clarify information provided by Exelon of the Peach Bottom LRA.
November 26, 2002	In a letter signed by M.P. Gallagher, Exelon submitted the response to Open Items and Confirmatory Items and Verification of Accuracy for Safety Evaluation Report (SER) Related to the License Renewal of Peach Bottom Atomic Power Station, Units 2 & 3.
December 19, 2002	In a letter signed by M.P. Gallagher, Exelon submitted the Amendment 1 to the Application for Renewal Operating License.
January 14, 2003	In a letter signed by M.P. Gallagher, Exelon submitted response to request for additional information related to license renewal.
January 29, 2003	In a letter signed by M.P. Gallagher, Exelon submitted the response to Teleconference Request to Modify Fuse Holder Inspection Program.

January 29, 2003	In a letter signed by M.P. Gallagher, Exelon submitted the response to Teleconference Request for Additional Clarification Related to SER Open Item 4.5.2-1 Response for Top Guide Inspection.
January 31, 2003	In a letter signed by M.P. Gallagher, Exelon submitted the response to request for additional information related to license renewal.
January 31, 2003	In a letter signed by M.P. Gallagher, Exelon submitted a list of future actions and a revision to the UFSAR Supplement for the Peach Bottom LRA.
February 3, 2003	In a letter to Exelon signed by R. Anand, NRC issued a summary of a teleconference between the staff and Exelon representatives. This teleconference was held on November 14, 2002 to discuss information in Section 4.3.2, "Reactor Vessel Internals Fatigue and Embrittlement" of the Peach Bottom LRA.
February 4, 2003	In a letter to Exelon signed by D. Solorio, NRC issued a summary of a conference call between the staff and Exelon representatives. This conference call was held on December 4, 2002 to discuss matters related to the NRC staff review of the Peach Bottom Atomic Power Station LRA.
February 4, 2003	In a letter to Exelon signed by D. Solorio, NRC issued a summary of a teleconference between the staff and Exelon representatives. This teleconference was held on November 5, 2002 to discuss matters related to the NRC staff review of the Peach Bottom LRA.
February 5, 2003	In a letter signed by M.P. Gallagher, Exelon submitted a revised list of future actions and a revision to the UFSAR Supplement for the Peach Bottom LRA.
February 5, 2003,	In a letter to Exelon signed by D. Solorio, NRC issued a summary of a to documented the receipt of draft responses to open and confirmatory Items for the Safety Evaluation Report for the Peach Bottom Atomic Power Station License Renewal Application.
February 6, 2003	In a letter to Exelon signed by D. Solorio, NRC issued a summary of discussions regarding a draft list of future commitments related to the safety evaluation report for the Peach Bottom Atomic Power Station license renewal application.
March __, 2003	In a letter to Exelon signed by D. Solorio, NRC issued Errata to License Renewal Safety Evaluation Report For Peach Bottom Atomic Power Station, Units 2 and 3 (ADAMS Accession No. ML030800392).

APPENDIX B

REFERENCES

This appendix lists the references used in preparing the safety evaluation report on the review of the license renewal application for Peach Bottom Atomic Power Station, Units 2 and 3, under Docket Numbers 50-277 and 50-278.

AMERICAN CONCRETE INSTITUTE (ACI)

ACI 301, "Specifications for Structural Concrete for Buildings"

ACI 318-63, "Building Code Requirements for Reinforced Concrete"

AMERICAN SOCIETY OF MECHANICAL ENGINEERS (ASME)

ASME Boiler and Pressure Vessel Code, July 1989

ASME Boiler and Pressure Vessel Code, Section III, Rules for Construction of Nuclear Power Plant Components (through Summer 1979 addenda)

ASME Boiler and Pressure Vessel Code, Section XI, Rules for Inservice Inspection of Nuclear Power Plant Components

ASME Boiler and Pressure Vessel Code, Section XI, Appendix G (1995 edition through 1996 addenda)

AMERICAN SOCIETY FOR TESTING AND MATERIALS (ASTM)

ASTM A307, "Standard Specification for Carbon Steel Bolts and Steels, 60,000 psi Tensile Strength"

ASTM A325, "Standard Specification for Structural Bolts, Steel, Heat-Treated, 120 ksi and 105 ksi Minimum Tensile Strength"

ASTM A490, "Standard Specification for Heat-Treated Steel Structural Bolts, 150ksi Minimum Tensile Strength"

ASTM D975-1981, "Standard Specification for Diesel Fuel Oils"

AMERICAN WATER WORKS ASSOCIATION (AWWA)

AWWA C203, "AWWA Standard for Coal-Tar Protective Coatings and Linings for Steel Water Pipelines - Enamel and Tape - Hot Applied," 1966

BOILING WATER REACTOR VESSEL AND INTERNALS PROJECT (BWRVIP)

BWRVIP-05, "BWR RPV Shell Weld Inspection Recommendations," September 1995

BWRVIP-18, “Core Spray Internals Inspection and Flaw Evaluation Guidelines,” July 1996

BWRVIP-25, “BWR Core Plate Inspection and Flaw Evaluation Guidelines,” October 1999

BWRVIP-26, “Top Guide Inspection and Flaw Evaluation Guidelines,” December 1996

BWRVIP-27, “Standby Liquid Control System/Core Plate ΔP Inspection and Flaw Evaluation Guidelines,” April 1997

BWRVIP-38, “Shroud Support Inspection and Flaw Evaluation Guidelines,” September 1997

BWRVIP-41, “BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines,” October 1997

BWRVIP-47, “BWR Lower Plenum Inspection and Flaw Evaluation Guidelines,” December 1997

BWRVIP-48, “Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines,” March 1998

BWRVIP-49, “Instrument Penetration Inspection and Flaw Evaluation Guidelines,” March 1998

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APPENDIX C
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Information Systems Laboratory (ISL)	Plant-Level Scoping Results

Appendix D
Commitment Listing

During the review of Exelon's LRA by the NRC staff, the applicant made commitments to provide aging management programs to manage aging effects on structures and components prior to the expiration of its current operating license terms. The following table lists these commitments along with their implementation schedule for each unit.

Item	Commitment	UFSAR Supplement Location	Implementation Schedule	Source
1	Evaluate any age related degradation found during recirculation system ISI inspections for applicability to the NSR portions of the recirculation system that was included in the scope of license renewal for NSR/SR.	A.1.8, ISI Program	Prior to period of extended operation.	Clarification to SER OI 2.3.3.19.2-1, letter dated January 14, 2003.
2	Notify the NRC whether Integrated Surveillance Program per BWRVIP-78 or plant specific program will be implemented	A.1.12, Reactor Materials Surveillance Program	Prior to period of extended operation	Response to RAI 3.1-15, letter dated May 6, 2002 and license condition
3	Perform Inspection of carbon steel Component Supports (Other than ASME Class 1, 2, 3, and ASME Class MC component supports)	A.1.16, Maintenance Rule Structural Monitoring Program	Prior to period of extended operation and every 4 years thereafter.	Response to RAI 3.5-2, letter dated May 21, 2002
4	Perform Inspection of SBO structural components	A.1.16, Maintenance Rule Structural Monitoring Program	Prior to period of extended operation and every 4 years thereafter.	Response to RAI 2.5-1, letter dated May 22, 2002.
5	Perform periodic reviews of calibration test results of electrical cables used in LPRM and WRM Instrumentation circuits to identify potential existence of aging degradation	A.1.17, Electrical Cables not subject to 10CFR50.49 Environmental Qualification Requirements used in Instrumentation Circuits	On-going	Response to SER Open Item 3.6.1.2.2-1, letter dated November 26, 2002.
6	Perform inspection of outer sluice gates in the circulating water pump structure	A.2.5, Outdoor, Buried, and Submerged Component Inspection Activities	Prior to period of extended operation	Response to RAI 3.5-3, letter dated May 21, 2002.
7	Perform inspection of hazard barrier doors in a sheltered environment for loss of material	A.2.6, Door Inspection Activities	Prior to period of extended operation and every 4 years thereafter	Response to RAI 3.5-2.A, letter dated May 21, 2002 and RAI 2.6-1, letter dated April 29, 2002.

Item	Commitment	UFSAR Supplement Location	Implementation Schedule	Source
8	Perform inspection of RPV top guide	A.2.7, Reactor Pressure Vessel and Internals ISI Program	Prior to period of extended operation	Response to SER Open Item 4.5.2-1, letter dated January 14, 2003.
9	Perform ultrasonic testing to detect wall thinning at susceptible locations in the ESW system stagnant piping in ECCS rooms	A.2.8, GL 89-13 Activities	Prior to period of extended operation	UFSAR Supplement Appendix A.2.8 letter dated November 26, 2002
10	Perform one-time inspection of a cast iron fire protection component for selective leaching	A.2.9, Fire Protection Activities	Prior to period of extended operation	UFSAR Supplement Appendix A.2.9 letter dated November 26, 2002
11	Perform functional testing of sprinkler heads	A.2.9, Fire Protection Activities	Prior to year 50 of sprinkler service life	UFSAR Supplement Appendix A.2.9 letter dated November 26, 2002
12	Perform inspection of electrical conduits in outdoor environment	A.2.9, Fire Protection Activities	Prior to period of extended operation	RAI 3.5.3 response, letter dated May 21, 2002
13	Perform inspection of Susquehanna substation wooden pole	A.2.11, Susquehanna Substation Wooden Pole Inspection Activity	2003 and every 10 years thereafter	UFSAR Supplement Appendix A.2.11 letter dated November 26, 2002
14	Perform one-time inspection of wall thickness of selected torus piping	A.3.1, Torus Piping Inspection Activities	Prior to period of extended operation	UFSAR Supplement Appendix A.3.1 letter dated November 26, 2002
15	Perform inspection of PVC-insulated Fire Safe Shutdown cables in drywell	A.3.2, FSSD Cable Inspection Activity	Prior to period of extended operation	UFSAR Supplement Appendix A.3.2 letter dated November 26, 2002
16	Implement inspection program for Non-EQ accessible cables and connections, including fuse blocks	A.3.3, Non-EQ Accessible Cable Aging Management Activity	Prior to period of extended operation and every 10 years thereafter	RAI 3.6-1 response letter dated April 29, 2002; and SER Confirmatory Item 3.6.2.2.2-1, letter dated November 26, 2002.
17	Perform one-time piping inspection activities for standby liquid control system, auxiliary steam system, plant equipment and floor drain system, service water system, radiation monitoring system	A.3.4, One-Time Piping Inspection Activities	Prior to period of extended operation	RAI B.1.13-1 response dated May 14, 2002; and RAI 2.1.2-3 and 2.1.2-4 response dated May 21, 2002
18	Perform one-time inspection of susceptible locations for loss of material in fuel pool cooling system to verify effectiveness of fuel pool chemistry activities	A.3.4, One-Time Piping Inspection Activities	Prior to period of extended operation	Response to SER Open Item 3.0.3.6.2-1, letter dated November 26, 2002

Item	Commitment	UFSAR Supplement Location	Implementation Schedule	Source
19	Perform one-time inspection of carbon steel piping for loss of material in RPV instrumentation and Reactor Recirculation system	A.3.4, One-Time Piping Inspection Activities	Prior to period of extended operation	Response to SER Open Item 3.1.3.2.1-1, letter dated November 26, 2002.
20	Perform testing of inaccessible medium voltage cables	A.3.5, Inaccessible Medium Voltage Cables not subject to 10CFR50.49 Environmental Qualification Requirements	Prior to period of extended operation	SER Open Item 3.6.1.2.1-1 response dated November 20, 2002
21	Implement the final version of the fuse holder interim staff guidance when issued by the NRC.	A.3.6, Fuse holder Aging Management Activity	Prior to period of extended operation	Response to SER Confirmatory Item 3.6.2.2.2-1, letter dated January 29, 2003.
22	Implement fatigue management program	A.4.2, Fatigue Management Activities	Prior to period of extended operation	UFSAR Supplement Appendix A.4.2 letter dated November 26, 2002
23	Submit RPV P-T curves for 54 EFPY as license amendment	A.5.1.1.2, P-T Limit Curves	Prior to period of extended operation	RAI 4.2-5 response dated May 1, 2002
24	Submit RPV circumferential weld examination relief request for 60 years	A.5.1.1.3, Reactor Vessel Circumferential Weld Examination Relief	Prior to period of extended operation	UFSAR Supplement Appendix A.5.1.1.3 letter dated November 26, 2002 and response to RAI 4.2-6, letter dated May 1, 2002.
25	Implement BWRVIP-76 when approved by the NRC and accepted by BWRVIP Committee	A.2.7, Reactor Pressure Vessel and Internals ISI Program	Prior to period of extended operation	License Condition
26	Obtain NRC review and approval for an inspection program if used, to manage the effects of fatigue for RPV studs when CUF approaches 1.0	A.5.2.1, Reactor Vessel Fatigue	Prior to period of extended operation	UFSAR Supplement Appendix A.5.2.1 and RAI 4.3-1 response dated May 1, 2002
27	Perform plant specific calculations for locations identified in NUREG/CR-6260 for older vintage plants to manage the effects of environmental fatigue. If position is modified based on industry activities, obtain NRC approval prior to implementation.	A.5.2.4, Effects of Reactor Coolant Environment on Fatigue Life of Components and Piping	Prior to period of extended operation	UFSAR Supplement Appendix A.5.2.4 and RAI 4.3-6 response dated May 1, 2002